CONTINENTAL RESOURCES INC
Form S-1/A
April 18, 2007
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As filed with the Securities and Exchange Commission on April 18, 2007

Registration No. 333-132257

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Amendment No. 6

to

FORM S-1

REGISTRATION STATEMENT

UNDER

THE SECURITIES ACT OF 1933

Continental Resources, Inc.

(Exact name of registrant as specified in charter)

Oklahoma	**1311**	**73-0767549**
(State or other jurisdiction of incorporation or organization)	**(Primary Standard Industrial Classification Code Number)**	**(I.R.S. Employer Identification Number)**

302 N. Independence

Enid, Oklahoma 73701

(580) 233-8955

(Address, including zip code, and telephone number, including area code, of registrant s principal executive offices)

Mark E. Monroe

President and Chief Operating Officer

302 N. Independence

Enid, Oklahoma 73701

(580) 233-8955

(Address, including zip code, and telephone number, including area code, of agent for service)

With a copy to:

David P. Oelman	**Joseph A. Hall**
Vinson & Elkins L.L.P.	**Davis Polk & Wardwell**
1001 Fannin, Suite 2300	**450 Lexington Avenue**
Houston, Texas 77002-6760	**New York, New York 10017**
(713) 758-2222	**(212) 450-4000**

Approximate date of commencement of proposed sale to the public: As soon as practicable on or after the effective date of this Registration Statement.

If any of the securities being registered on this Form are to be offered on a delayed or continuous basis pursuant to Rule 415 under the Securities Act of 1933, check the following box. ¨

If this Form is filed to register additional securities for an offering pursuant to Rule 462(b) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. ¨

If this Form is a post-effective amendment filed pursuant to Rule 462(c) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. ¨

If this Form is a post-effective amendment filed pursuant to Rule 462(d) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. ¨

CALCULATION OF REGISTRATION FEE

Title of Each Class of Securities to be Registered	Amount to be Registered	Proposed Maximum Offering Price per Share	Proposed Maximum Aggregate Offering Price	Amount of Registration Fee
Common stock, par value $.01	33,925,000(1)	$18.00(2)	$610,650,000(1)(2)	$62,620(3)

(1) Includes common stock issuable upon exercise of the underwriters option to purchase additional shares of common stock.
(2) Estimated solely for the purpose of calculating the registration fee pursuant to Rule 457(a).
(3) The registrant previously paid $61,525 as a registration fee in connection with this Registration Statement on Form S-1, Registration No. 333-132257, filed on March 7, 2006, as amended, for a proposed maximum aggregate offering price of $575,000,000. The balance of $1,095 to be paid in connection herewith represents the registration fee necessary for registering the additional $35,650,000 of securities.

The registrant hereby amends this registration statement on such date or dates as may be necessary to delay its effective date until the registrant shall file a further amendment which specifically states that this registration statement shall thereafter become effective in accordance with Section 8(a) of the Securities Act of 1933 or until the registration statement shall become effective on such date as the Securities and Exchange Commission, acting pursuant to said Section 8(a), may determine.

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The information in this prospectus is not complete and may be changed. These securities may not be sold until the registration statement filed with the Securities and Exchange Commission is effective. This prospectus is not an offer to sell these securities nor does it seek an offer to buy these securities in any state where the offer or sale is not permitted.

Subject to completion, dated April 18, 2007

PROSPECTUS

29,500,000 Shares

Continental Resources, Inc.

Common Stock

This is our initial public offering of common stock. We are offering 8,850,000 shares of our common stock. The selling shareholder identified in this prospectus is offering 20,650,000 shares of our common stock. We will not receive any proceeds from the sale of the shares by the selling shareholder. The estimated initial public offering price is between $16.00 and $18.00 per share.

Prior to this offering, there has been no public market for our common stock. Our common stock has been approved for listing on the New York Stock Exchange, subject to official notice of issuance, under the symbol CXP.

Investing in our common stock involves a high degree of risk. See Risk Factors beginning on page 11.

	Per share	Total

	Per Share	Total
Initial public offering price	$	$
Underwriting discount	$	$
Proceeds to Continental Resources, Inc.(1)	$	$
Proceeds to selling shareholder(1)	$	$

(1) Expenses, other than underwriting discounts related to the shares sold by the selling shareholder, associated with the offering will be paid by us.

The selling shareholder has granted the underwriters an option for a period of 30 days to purchase up to 4,425,000 additional shares of common stock to cover overallotments, if any. If such option is exercised in full, the total underwriting discount will be $ and the total proceeds to the selling shareholder will be $.

Neither the Securities and Exchange Commission nor any state securities commission has approved or disapproved of these securities or passed upon the adequacy or accuracy of this prospectus. Any representation to the contrary is a criminal offense.

The underwriters expect to deliver the shares of common stock to investors on , 2007.

JPMorgan **Merrill Lynch & Co.**

Citi

UBS Investment Bank

Deutsche Bank Securities

Raymond James

, 2007

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Cautionary Statement Regarding Forward-Looking Statements

This prospectus contains forward-looking statements that are subject to a number of risks and uncertainties, many of which are beyond our control. All statements, other than statements of historical fact included in this prospectus, regarding our strategy, future operations, financial position, estimated revenues and losses, projected costs, prospects, plans and objectives of management are forward-looking statements. When used in this prospectus, the words could, believe, anticipate, intend, estimate, expect, project and similar expressions are intended to id forward-looking statements, although not all forward-looking statements contain such identifying words.

Forward-looking statements may include statements about our:

- business strategy;
- reserves;
- technology;
- financial strategy;
- oil and natural gas realized prices;
- timing and amount of future production of oil and natural gas;
- the amount, nature and timing of capital expenditures;
- drilling of wells;
- competition and government regulations;
- marketing of oil and natural gas;
- exploitation or property acquisitions;
- costs of exploiting and developing our properties and conducting other operations;

general economic conditions;

uncertainty regarding our future operating results; and

plans, objectives, expectations and intentions contained in this prospectus that are not historical.

All forward-looking statements speak only as of the date of this prospectus. You should not place undue reliance on these forward-looking statements. Although we believe that our plans, intentions and expectations reflected in or suggested by the forward-looking statements we make in this prospectus are reasonable, we can give no assurance that these plans, intentions or expectations will be achieved. We disclose important factors that could cause our actual results to differ materially from our expectations under Risk Factors and Management s Discussion and Analysis of Financial Condition and Results of Operations and elsewhere in this prospectus. These cautionary statements qualify all forward-looking statements attributable to us or persons acting on our behalf.

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Industry and Market Data

The market data and certain other statistical information used throughout this prospectus are based on independent industry publications, government publications or other published independent sources. Some data are also based on our good faith estimates. Although we believe these third-party sources are reliable, we have not independently verified the information and cannot guarantee its accuracy and completeness.

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Prospectus Summary

This summary highlights information contained elsewhere in this prospectus. You should read this entire prospectus carefully, including Risk Factors and our historical consolidated financial statements and the notes to those historical consolidated financial statements included elsewhere in this prospectus. Unless the context otherwise requires, references in this prospectus to Continental Resources, we, us, our, ours or company refer to Continental Resources, Inc. and its subsidiary.

We have provided definitions for the oil and natural gas terms used in this prospectus in the Glossary of Oil and Natural Gas Terms beginning on page A-1 of this prospectus. Unless otherwise indicated, the information contained in this prospectus assumes that the underwriters do not exercise their overallotment option to purchase additional shares.

Our Business

We are an independent oil and natural gas exploration and production company with operations in the Rocky Mountain, Mid-Continent and Gulf Coast regions of the United States. We focus our exploration activities in large new or developing plays that provide us the opportunity to acquire undeveloped acreage positions for future drilling operations. We have been successful in targeting large repeatable resource plays where horizontal drilling, advanced fracture stimulation and enhanced recovery technologies provide the means to economically develop and produce oil and natural gas reserves from unconventional formations. As a result of these efforts, we have grown substantially through the drillbit, adding 96.2 MMBoe of proved oil and natural gas reserves through extensions and discoveries from January 1, 2001 through December 31, 2006 compared to 5.1 MMBoe added through proved reserve purchases during that same period.

As of December 31, 2006, our estimated proved reserves were 118.3 MMBoe, with estimated proved developed reserves of 87.1 MMBoe, or 74% of our total estimated proved reserves. Crude oil comprised 83% of our total estimated proved reserves. At December 31, 2006, we had 1,772 scheduled drilling locations on the 1,775,000 gross (1,071,000 net) acres that we held. For the year ended December 31, 2006, we generated revenues of $483.7 million, and operating cash flows of $417.0 million.

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The following table summarizes our total estimated proved reserves, PV-10 and net producing wells as of December 31, 2006, average daily production for the three months ended December 31, 2006 and the reserve-to-production ratio in our principal regions. Our reserve estimates as of December 31, 2006 are based primarily on a reserve report prepared by Ryder Scott Company, L.P., our independent reserve engineers. In preparing its report, Ryder Scott Company, L.P. evaluated properties representing approximately 83% of our PV-10. Our technical staff evaluated properties representing the remaining 17% of our PV-10.

	At December 31, 2006				Average daily production		
	Proved reserves (MBoe)	Percent of total	PV-10(1) (in millions)	Net producing wells	Fourth quarter 2006 (Boe per day)	Percent of total	Annualized reserve/ production index(2)
Rocky Mountain:							
Red River units	66,527	56%	$ 791	201	11,732	44%	15.5
Bakken field	25,623	22%	441	66	7,905	30%	8.9
Other	9,077	8%	104	233	1,717	7%	14.5
Mid-Continent	16,894	14%	244	672	4,280	16%	10.8
Gulf Coast	228		4	19	869	3%	0.7
Total	118,349	100%	$ 1,584	1,191	26,503	100%	12.2

(1) PV-10 is a non GAAP financial measure and generally differs from Standardized Measure, the most directly comparable GAAP financial measure, because it does not include the effects of income taxes on future net revenues. However, our PV-10 and our Standardized Measure are equivalent because we are a subchapter S-corporation. In connection with the closing of this offering, we will convert to a subchapter C-corporation. Our pro-forma Standardized Measure, assuming our conversion to a subchapter C-corporation, was $1.0 billion at December 31, 2006. Neither PV-10 nor Standardized Measure represents an estimate of the fair market value of our oil and gas properties. We and others in the industry use PV-10 as a measure to compare the relative size and value of proved reserves held by companies without regard to the specific tax characteristics of such entities.

(2) The Annualized Reserve/Production Index is the number of years proved reserves would last assuming current production continued at the same rate. This index is calculated by dividing annualized fourth quarter 2006 production into the proved reserve quantity at December 31, 2006.

The following table provides additional information regarding our key development areas:

	At December 31, 2006					2007 Budget	
	Developed acres		Undeveloped acres				
	Gross	Net	Gross	Net	Scheduled drilling locations(1)	Wells planned for drilling	Capital expenditures (in millions)
Rocky Mountain:							
Red River units	144,309	128,484			133	51	$ 151
Bakken field	81,761	60,176	581,846	342,321	804	58	145
Other	49,010	38,534	375,185	213,516	66	12	13
Mid-Continent	147,681	94,214	335,982	175,780	762	151	122

Gulf Coast	41,450	11,869	17,368	6,360	7	3	6
Total	464,211	333,277	1,310,381	737,977	1,772	275	$ 437

(1) Scheduled drilling locations represent total gross locations specifically identified and scheduled by management as an estimate of our future multi-year drilling activities on existing acreage. Of the total locations shown in the table, 249 are classified as PUDs. As of April 12, 2007, we have commenced drilling 116 locations shown in the table, including 67 PUD locations. Our actual drilling activities may change depending on oil and natural gas prices, the availability of capital, costs, drilling results, regulatory approvals and other factors. See Risk Factors Risks Relating to the Oil and Natural Gas Industry and Our Business.

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Our Business Strategy

Our goal is to increase shareholder value by finding and developing crude oil and natural gas reserves at costs that provide an attractive rate of return on our investment. The principal elements of our business strategy are:

Growth Through Drilling. Substantially all of our annual capital expenditures are invested in drilling projects and acreage and seismic acquisitions.

Internally Generate Prospects. Our technical staff has internally generated substantially all of the opportunities for the investment of our capital. Because we have been an early entrant in new or emerging plays, our costs to acquire undeveloped acreage have generally been less than those of later entrants into a developing play.

Focus on Unconventional Oil and Natural Gas Resource Plays. Our experience with horizontal drilling, advanced fracture stimulation and enhanced recovery technologies allows us to commercially develop unconventional oil and natural gas resource plays, such as the Red River B dolomite, Bakken Shale and Woodford Shale formations.

Acquire Significant Acreage Positions in New or Developing Plays. Our technical staff is focused on identifying and testing new unconventional oil and natural gas resource plays where significant reserves could be developed if commercial production rates can be achieved through advanced drilling, fracture stimulation and enhanced recovery techniques.

Our Business Strengths

We have a number of strengths that we believe will help us successfully execute our strategies:

Large Drilling and Acreage Inventory. Our large number of identified drilling locations in all of our areas of operations provide for a multi-year drilling inventory.

Horizontal Drilling and Enhanced Recovery Experience. In 1992, we drilled our initial horizontal well, and we have drilled over 350 horizontal wells since that time. We also have substantial experience with enhanced recovery methods and currently serve as the operator of 48 waterflood units and eight high-pressure air injection units.

Control Operations Over a Substantial Portion of our Assets and Investments. As of December 31, 2006, we operated properties comprising 95% of our PV-10. By controlling operations, we are able to more effectively manage the cost and timing of exploration and development of our properties.

Experienced Management Team. Our senior management team has extensive expertise in the oil and gas industry. Our seven senior officers have an average of 26 years of oil and gas industry experience.

Strong Financial Position. As of April 12, 2007, we had outstanding borrowings under our credit facility of approximately $269.5 million. We believe that our planned exploration and development activities will be funded substantially from our operating cash flows. After giving effect to this offering at an assumed public offering price of $17.00 per share and the application of the net proceeds we will receive in this offering, we expect to have borrowings of approximately $129.9 million outstanding under our credit facility.

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Recent Events

Cash Dividends. On January 10, 2007, we declared a cash dividend of approximately $18.8 million to our shareholders and, subject to forefeiture, to holders of unvested restricted stock. On January 31, 2007, we paid $18.7 million of the dividend declared, of which $16.9 million was paid to our principal shareholder. On March 6, 2007, we declared a cash dividend of approximately $33.3 million to our shareholders and, subject to forfeiture, to holders of unvested restricted stock. On April 12, 2007, we paid $33.1 million of the dividend declared, of which $30.0 million was paid to our principal shareholder. We are currently a subchapter S-corporation under the rules and regulations of the Internal Revenue Service. As a result, income taxes attributable to our federal and state income are payable by our shareholders. The dividends have been paid to shareholders to fund their taxes due and estimated tax payments. In connection with the completion of this offering, we will convert from a subchapter S-corporation to a subchapter C-corporation, and we do not anticipate paying any additional cash dividends on our common stock in the foreseeable future. The selling shareholder has received dividends of approximately $13.5 million, $1.8 million, $79.0 million and $46.9 million in 2004, 2005, 2006 and 2007, respectively. The total net proceeds to the selling shareholder in this offering will be approximately $330.0 million, or approximately $400.7 million if the underwriters exercise their overallotment option in full, in each case assuming an initial public offering price of $17.00 per share, which is the midpoint of the range set forth on the cover of this prospectus.

Risk Factors

Investing in our common stock involves risks that include the speculative nature of oil and natural gas exploration, competition, volatile oil and natural gas prices and other material factors. You should read carefully the section entitled Risk Factors beginning on page 11 for an explanation of these risks before investing in our common stock. In particular, the following considerations may offset our business strengths or have a negative effect on our business strategy as well as on activities on our properties, which could cause a decrease in the price of our common stock and result in a loss of all or a portion of your investment:

- A substantial or extended decline in oil and natural gas prices may adversely affect our business, financial condition or results of operations and our ability to meet our capital expenditure obligations and financial commitments.

- Drilling for and producing oil and natural gas are high risk activities with many uncertainties that could adversely affect our business, financial condition or results of operations.

- Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.

- Our use of enhanced recovery methods creates uncertainties that could adversely affect our results of operations and financial condition.

- Our development and exploitation projects require substantial capital expenditures. We may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a decline in our oil and natural gas reserves.

- If oil and natural gas prices decrease, we may be required to take write-downs of the carrying values of our oil and natural gas properties.

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Unless we replace our oil and natural gas reserves, our reserves and production will decline, which would adversely affect our cash flows and results of operations.

The unavailability or high cost of additional drilling rigs, equipment, supplies, personnel and oilfield services could adversely affect our ability to execute our exploration and development plans within our budget and on a timely basis.

We may incur substantial losses and be subject to substantial liability claims as a result of our oil and natural gas operations; we may not be insured for, or our insurance may be inadequate to protect us against, these risks.

Prospects that we decide to drill may not yield oil or natural gas in commercially viable quantities.

Our identified drilling locations are scheduled out over several years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling.

Following this offering, our Chairman and Chief Executive Officer will own approximately 73.2% of our outstanding common stock, giving him influence and control in corporate transactions and other matters.

For a discussion of other considerations that could negatively affect us, including risks related to this offering and our common stock, see Risk Factors and Cautionary Statement Regarding Forward-Looking Statements.

Corporate History and Information

Continental Resources, Inc. is incorporated under the laws of the State of Oklahoma. We were originally formed in 1967 to explore, develop and produce oil and natural gas properties in Oklahoma. Through 1993, our activities and growth remained focused primarily in Oklahoma. In 1993, we expanded our activity into the Rocky Mountain and Gulf Coast regions. Through drilling success and strategic acquisitions, approximately 86% of our estimated proved reserves as of December 31, 2006 are located in the Rocky Mountain region.

We are currently a subchapter S-corporation under the rules and regulations of the Internal Revenue Service. However, upon the consummation of this offering, we will have more shareholders than the IRS rules and regulations governing S-corporations allow, and, therefore, we will convert automatically from a subchapter S-corporation to a subchapter C-corporation. In connection with this conversion, we will record a charge to earnings (estimated to be approximately $178.8 million as if the conversion occurred on December 31, 2006) to recognize deferred taxes.

In addition, concurrent with the closing of this offering, we will effect an 11 for 1 stock split of our shares in the form of a stock dividend.

Our principal executive offices are located at 302 N. Independence, Enid, Oklahoma 73701, and our telephone number at that address is (580) 233-8955.

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The Offering

Common Stock Offered:

By Continental Resources, Inc.: 8,850,000 shares

By the selling shareholder: 20,650,000 shares

Overallotment option granted by the selling shareholder: 4,425,000 shares

Common stock to be owned by the selling shareholder after the offering: 122,980,608 shares (or 118,555,608 shares if the underwriters overallotment option is exercised in full)

Common stock to be outstanding after the offering: 168,005,799 shares

Use of Proceeds:

We expect to receive approximately $139.6 million of net proceeds from the sale of the common stock offered by us, based upon the assumed initial public offering price of $17.00 per share (the midpoint of the price range set forth on the cover page of this prospectus), after deducting underwriting discounts and estimated offering expenses. Each $1.00 increase (decrease) in the public offering price would increase (decrease) our net proceeds by approximately $8.3 million. We intend to use all of the net proceeds we receive from this offering to repay a portion of borrowings outstanding under our credit facility. We will not receive any proceeds from the sale of the shares of common stock by the selling shareholder. See Use of Proceeds.

Dividend Policy:

We do not anticipate paying any cash dividends on our common stock. See Dividend Policy.

New York Stock Exchange Symbol:

CXP

Other Information About This Prospectus:

Unless specifically stated otherwise, the information in this prospectus:

- is adjusted to reflect an 11 for 1 stock split of our shares of common stock to be effected in the form of a stock dividend concurrent with the consummation of this offering;
- assumes no exercise of the underwriters overallotment option to purchase additional shares; and
- assumes an initial public offering price of $17.00, which is the midpoint of the range set forth on the front cover of this prospectus.

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Summary Historical and Pro Forma Consolidated Financial Data

This section presents our summary historical and pro forma consolidated financial data. The summary historical consolidated financial data presented below is not intended to replace our historical consolidated financial statements.

The following historical consolidated financial data, as it relates to each of the fiscal years ended December 31, 2004 through 2006, has been derived from our audited historical consolidated financial statements for such periods. You should read the following summary historical consolidated financial data in connection with Capitalization, Management s Discussion and Analysis of Financial Condition and Results of Operations and our historical consolidated financial statements and related notes included elsewhere in this prospectus. The summary historical consolidated results are not necessarily indicative of results to be expected in future periods.

The summary pro forma financial data reflect the tax effects of our conversion, concurrent with the closing of this offering, from a subchapter S-corporation to a subchapter C-corporation and the earnings per share impact of our 11 for 1 stock split to be effected in the form of a stock dividend concurrent with the closing of this offering.

	Year ended December 31,		
	2004	2005	2006
	(in thousands, except per share amounts)		
Statement of operations data:			
Revenues:			
Oil and natural gas sales	$ 181,435	$ 361,833	$ 468,602
Crude oil marketing and trading(1)	226,664		
Oil and natural gas service operations	10,811	13,931	15,050
Total revenues	418,910	375,764	483,652
Operating costs and expenses:			
Production expense	43,754	52,754	62,865
Production tax	12,297	16,031	22,331
Exploration expense	12,633	5,231	19,738
Crude oil marketing and trading(1)	227,210		
Oil and gas service operations	6,466	7,977	8,231
Depreciation, depletion, amortization and accretion	38,627	49,802	65,428
Property impairments	11,747	6,930	11,751
General and administrative(2)	12,400	31,266	23,016
(Gain) loss on sale of assets	150	(3,026)	(290)
Total operating costs and expenses	$ 365,284	$ 166,965	$ 213,070
Income from operations	$ 53,626	$ 208,799	$ 270,582
Other income (expense)			
Interest expense	(23,617)	(14,220)	(11,310)

Loss on redemption of bonds	(4,083)		
Other	890	867	1,742
Total other income (expense)	(26,810)	(13,353)	(9,568)

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	Year ended December 31,		
	2004	2005	2006
	(in thousands, except per share amounts)		
Income from continuing operations before income taxes	26,816	195,446	261,014
Provision (benefit) for income taxes(3)		1,139	(132)
Income from continuing operations	26,816	194,307	261,146
Discontinued operations(4)	1,680		
Loss on sale of discontinued operations(4)	(632)		
Net income	$ 27,864	$ 194,307	$ 261,146
Basic earnings per share:			
From continuing operations	$ 1.87	$ 13.52	$ 18.17
From discontinued operations(4)	0.11		
Loss on sale of discontinued operations(4)	(0.04)		
Net income per share	$ 1.94	$ 13.52	$ 18.17
Shares used in basic earnings per share	14,369	14,369	14,374
Diluted earnings per share:			
From continuing operations	$ 1.85	$ 13.42	$ 17.99
From discontinued operations(4)	0.12		
Loss on sale of discontinued operations(4)	(0.04)		
Net income per share	$ 1.93	$ 13.42	$ 17.99
Shares used in diluted earnings per share	14,476	14,482	14,515
Pro forma C-corporation and stock split data:			
Income from continuing operations before income taxes	$ 26,816	$ 195,446	$ 261,014
Pro forma provision for income taxes attributable to operations	10,190	74,269	99,185
Pro forma income from operations after tax	16,626	121,177	161,829
Discontinued operations, net of tax(4)	1,042		
Loss on sale of discontinued operations, net of tax(4)	(392)		
Pro forma net income	$ 17,276	$ 121,177	$ 161,829
Pro forma basic earnings per share	$ 0.11	$ 0.77	$ 1.02
Pro forma diluted earnings per share	0.11	0.76	1.01
Other financial data:			
Cash dividends per share	$ 1.04	$ 0.14	$ 6.06
EBITDAX (5)	116,498	285,344	372,115
Net cash provided by operations	93,854	265,265	417,041
Net cash used in investing	(72,992)	(133,716)	(324,523)
Net cash used in financing	(7,245)	(141,467)	(91,451)

Capital expenditures	94,307	144,800	326,579
Balance sheet data at December 31:			
Cash and cash equivalents	$ 15,894	$ 6,014	$ 7,018
Property and equipment, net	434,339	509,393	751,747
Total assets	504,951	600,234	858,929
Long-term debt, including current maturities	290,522	143,000	140,000
Shareholders equity	130,385	324,730	498,519

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(1) Crude oil marketing and trading captions consist of our marketing activities under which crude oil production was sold at the wellhead and transported to a local hub where we purchased the barrels back to exchange at Cushing, Oklahoma in order to minimize pricing differentials with the NYMEX oil futures contract. We adopted Emerging Issues Task Force (EITF) 04-13 on January 1, 2005, which allowed certain purchase and sales transactions with the same counterparty to be combined and accounted for as a single transaction under the guidance of Accounting Principles Board Opinion No. 29. In 2005, we netted $39.8 million of crude oil marketing and trading revenues and $39.7 million of crude oil marketing and trading expenses under oil and natural gas sales. Prior to the adoption of EITF 04-13, we presented crude oil marketing and trading revenues and expenses gross under the guidance provided by EITF 99-19, Reporting Revenues Gross as a Principal and/or Net as an Agent. Effective March 2005, we ceased marketing our crude oil production under these arrangements. Thereafter, we have sold our crude oil at the wellhead. Certain of these sales have been to our affiliates, as described under Certain Relationships and Related Party Transactions.

(2) We have included stock-based compensation of $2.0 million, $13.7 million and $2.9 million in general and administrative expenses for the years ended December 31, 2004, 2005 and 2006, respectively. Our stock based compensation plans require us to purchase vested shares of restricted stock and shares issued upon the exercise of stock options at the plan participant s request based on an internally calculated value of our stock. In addition, we have the right to purchase vested shares of restricted stock and shares issued upon the exercise of stock options at the same price from plan participants upon termination of the participant s employment with us for any reason for a period of two years after the termination date. Amounts noted herein represent the increase in our liability associated with our purchase obligation. The valuation is based on the book value of our shareholders equity adjusted for our PV-10 as of each calendar quarter. Our requirement and right, as applicable, to purchase vested shares will be eliminated once we begin reporting under Section 12 of the Securities Exchange Act of 1934, as amended (the Exchange Act). As a result of this change, we will recognize a non-cash charge to earnings upon completion of this offering. As of December 31, 2006, the non-cash charge to earnings would have been approximately $17.4 million, assuming an initial offering price of $17.00 per share. See Capitalization.

(3) Properties owned by us at May 31, 1997, the date we converted into a subchapter S-corporation from a subchapter C-corporation, may be subject to federal taxation if sold for an amount in excess of the then tax basis for the sold assets. During 2005, we incurred federal taxes due to the sale of assets acquired prior to May 31, 1997. The benefit recorded during 2006 reflects a change in estimate of the original provision recorded for federal taxes incurred.

(4) In July 2004, we sold all of the outstanding stock in Continental Gas, Inc., a wholly owned subsidiary, to our shareholders. The Continental Gas, Inc. assets included seven gas gathering systems and three gas-processing plants. These assets represented our entire gas gathering, marketing and processing segment. We have accounted for these operations as discontinued operations.

(5) EBITDAX represents earnings before interest expense, income taxes (when applicable), depreciation, depletion, amortization and accretion, property impairments, exploration expense and non-cash compensation expense. EBITDAX is not a measure of net income or cash flow as determined by generally accepted accounting principles (GAAP). EBITDAX should not be considered as an alternative to, or more meaningful than, net income or cash flow as determined in accordance with GAAP or as an indicator of a company s operating performance or liquidity. Certain items excluded from EBITDAX are significant components in understanding and assessing a company s financial performance, such as a company s cost of capital and tax structure, as well as the historic costs of depreciable assets, none of which are components of EBITDAX. Our computations of EBITDAX may not be comparable to other similarly titled measures of other companies. We believe that EBITDAX is a widely followed measure of operating performance and may also be used by investors to measure our ability to meet future debt service requirements, if any. Our credit facility requires that we maintain a total debt to EBITDAX ratio of no greater than 3.75 to 1 on a rolling four-quarter basis. Our credit facility defines EBITDAX consistently with the definition of EBITDAX utilized and presented by us. At December 31, 2005 and 2006, this ratio was approximately 0.5 to 1 and 0.4 to 1, respectively. The following table represents a reconciliation of our net income to EBITDAX:

	Year ended December 31,		
	2004	2005	2006
	(in thousands)		
Net income	$ 27,864	$ 194,307	$ 261,146
Interest expense	23,617	14,220	11,310
Provision (benefit) for income taxes		1,139	(132)
Depreciation, depletion, amortization and accretion	38,627	49,802	65,428
Property impairments	11,747	6,930	11,751
Exploration expense	12,633	5,231	19,738
Equity compensation	2,010	13,715	2,874

EBITDAX	$ 116,498	$ 285,344	$ 372,115

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Summary Reserve, Production and Operating Data

The following table presents summary data with respect to our estimated net proved oil and natural gas reserves as of the dates indicated. Our reserve estimates as of December 31, 2004, 2005 and 2006 are based primarily on reserve reports prepared by Ryder Scott Company, L.P., our independent reserve engineers. In preparing its reports, Ryder Scott Company, L.P. evaluated properties representing approximately 83% of our PV-10 as of the end of each period. Our technical staff evaluated our remaining properties. A copy of Ryder Scott Company, L.P. s summary report as of December 31, 2006 is included in this prospectus beginning on page B-1. All calculations of estimated net proved reserves have been made in accordance with the rules and regulations of the Securities and Exchange Commission, or the SEC. For additional information regarding our reserves, see Business and Properties Proved Reserves.

	As of December 31,		
	2004	2005	2006
Proved reserves:			
Oil (MBbls)	80,602	98,645	98,038
Natural gas (MMcf)	60,620	108,118	121,865
Oil equivalents (MBoe)	90,705	116,665	118,349
Proved developed reserves percentage	83%	69%	74%
PV-10 (in millions)(1)	$ 1,114	$ 2,204	$ 1,584
Estimated reserve life (in years)	17.6	16.2	13.1
Costs incurred (in thousands):			
Property acquisition costs	$ 12,456	$ 16,763	$ 36,534
Exploration costs	30,867	9,289	68,686
Development costs	53,036	117,837	221,286
Total	$ 96,359	$ 143,889	$ 326,506

(1) PV-10 is a non GAAP financial measure and generally differs from Standardized Measure, the most directly comparable GAAP financial measure, because it does not include the effects of income taxes on future net revenues. However, our PV-10 and our Standardized Measure are equivalent because we are a subchapter S-corporation. In connection with the closing of this offering, we will convert to a subchapter C-corporation. Our pro-forma Standardized Measure, assuming our conversion to a subchapter C-corporation, was $1.0 billion at December 31, 2006. Neither PV-10 nor Standardized Measure represents an estimate of the fair market value of our oil and gas properties. We and others in the industry use PV-10 as a measure to compare the relative size and value of proved reserves held by companies without regard to the specific tax characteristics of such entities.

The following table sets forth summary data with respect to our production results, average sales prices and production costs on a historical basis for the periods presented:

	Year ended December 31,		
	2004	2005	2006
Net production volumes:			
Oil (MBbls)(1)	3,688	5,708	7,480

Natural gas (MMcf)	8,794	9,006	9,225
Oil equivalents (MBoe)	5,154	7,209	9,018
Average prices(1):			
Oil, without hedges ($/Bbl)	$ 38.85	$ 52.45	$ 55.30
Oil, with hedges ($/Bbl)	37.12	52.45	55.30
Natural gas ($/Mcf)	5.06	6.93	6.08
Oil equivalents, without hedges ($/Boe)	36.45	50.19	52.09
Oil equivalents, with hedges ($/Boe)	35.20	50.19	52.09
Costs and expenses(1):			
Production expense ($/Boe)	$ 8.49	$ 7.32	$ 6.99
Production tax ($/Boe)	2.39	2.22	2.48
General and administrative ($/Boe)	2.41	4.34	2.56
DD&A expense ($/Boe)(2)	7.02	6.50	6.91

(1) Oil sales volumes are 21 MBbls less than oil production volumes for the year ended December 31, 2006. Average prices and per unit costs have been calculated using sales volumes.

(2) Rate is determined based on DD&A expense derived from oil and natural gas assets.

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Risk Factors

You should carefully consider each of the risks described below, together with all of the other information contained in this prospectus, before deciding to invest in shares of our common stock. If any of the following risks develop into actual events, our business, financial condition or results of operations could be materially adversely affected, the trading price of your shares could decline and you may lose all or part of your investment.

Risks Relating to the Oil and Natural Gas Industry and Our Business

A substantial or extended decline in oil and natural gas prices may adversely affect our business, financial condition or results of operations and our ability to meet our capital expenditure obligations and financial commitments.

The price we receive for our oil and natural gas production heavily influences our revenue, profitability, access to capital and future rate of growth. Oil and natural gas are commodities and, therefore, their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. Historically, the markets for oil and natural gas have been volatile. These markets will likely continue to be volatile in the future. The prices we receive for our production, and the levels of our production, depend on numerous factors beyond our control. These factors include the following:

- changes in global supply and demand for oil and natural gas;
- the actions of the Organization of Petroleum Exporting Countries, or OPEC;
- the price and quantity of imports of foreign oil and natural gas;
- political conditions in or affecting other oil-producing and natural gas-producing countries, including the current conflicts in the Middle East and conditions in South America and Russia;
- the level of global oil and natural gas exploration and production;
- the level of global oil and natural gas inventories;
- localized supply and demand fundamentals and transportation availability;
- weather conditions;

technological advances affecting energy consumption; and

the price and availability of alternative fuels.

Lower oil and natural gas prices will reduce our cash flows and borrowing ability. See Our development and exploitation projects require substantial capital expenditures. We may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a decline in our oil and natural gas reserves. Lower oil and natural gas prices may also reduce the amount of oil and natural gas that we can produce economically. Substantial decreases in oil and natural gas prices would render uneconomic a significant portion of our exploitation projects. This may result in our having to make significant downward adjustments to our estimated proved reserves. As a result, a substantial or extended decline in oil or natural gas prices may materially and adversely affect our future business, financial condition, results of operations, liquidity or ability to finance planned capital expenditures.

In addition, because our producing properties are geographically concentrated in the Rocky Mountain region, we are vulnerable to fluctuations in pricing in that area. In particular, 81% of our production during the fourth quarter of 2006 was from the Rocky Mountain region. As a result of this concentration, we may be disproportionately exposed to the impact of regional supply and demand factors, transportation capacity

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constraints, curtailment of production or interruption of transportation of oil produced from the wells in these areas. Such factors can cause significant fluctuation in our realized oil and natural gas prices. For example, the company-wide difference between the average NYMEX oil price and our average realized oil price for the year ended December 31, 2005 was $5.24 per Bbl, whereas the company-wide difference between the NYMEX oil price and our realized oil price for the year ended December 31, 2006 was $11.04 per Bbl. The increase in the difference was caused by higher oil imports and production in the Rocky Mountain region, lower demand by local Rocky Mountain refineries due to downtime for maintenance and reduced seasonal demand for gasoline and downstream transportation capacity constraints. We are unable to predict when, or if, the difference will revert back to pre-2006 levels. If such significant price differentials continue, our future business, financial condition and results of operations may be materially adversely affected.

Drilling for and producing oil and natural gas are high risk activities with many uncertainties that could adversely affect our business, financial condition or results of operations.

Our future financial condition and results of operations will depend on the success of our exploitation, exploration, development and production activities. Our oil and natural gas exploration and production activities are subject to numerous risks beyond our control, including the risk that drilling will not result in commercially viable oil or natural gas production. We expect to invest approximately 45% of our exploration and development capital during 2007 in two relatively new unconventional projects, the Bakken Shale in western North Dakota and the Woodford Shale in eastern Oklahoma. Due to limited production history from the relatively few number of wells drilled in these projects, we are unable to predict with certainty the quantity of future production from wells to be drilled in those projects. Our decisions to purchase, explore, develop or otherwise exploit prospects or properties will depend in part on the evaluation of data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are often inconclusive or subject to varying interpretations. For a discussion of the uncertainty involved in these processes, see Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves. Our cost of drilling, completing and operating wells is often uncertain before drilling commences. For example, our exploration expenses increased more significantly than we had expected in 2006 to $19.7 million, primarily due to increased dry hole expenses in each of the Rocky Mountain, Mid-Continent and Gulf Coast regions as a result of a higher level of drilling in 2006. In addition, impairment provisions for our developed oil and natural gas properties increased to $6.3 million for the year ended December 31, 2006 as a result of developmental well dry holes and properties where the associated field level reserves were not sufficient to recover capitalized drilling and completion costs. Overruns in budgeted expenditures are common risks that can make a particular project uneconomical.

Further, many factors may curtail, delay or cancel our scheduled drilling projects, including the following:

- delays imposed by or resulting from compliance with regulatory requirements;
- pressure or irregularities in geological formations;
- shortages of or delays in obtaining equipment and qualified personnel;
- equipment failures or accidents;
- adverse weather conditions, such as hurricanes and tropical storms;

reductions in oil and natural gas prices;

title problems; and

limitations in the market for oil and natural gas.

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Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.

We estimate that our proved reserves as of December 31, 2006 were 118.3 MMBoe with a PV-10 of approximately $1,584 million. The process of estimating oil and natural gas reserves is complex. It requires interpretations of available technical data and many assumptions, including assumptions relating to economic factors. Any significant inaccuracies in these interpretations or assumptions could materially affect our estimated quantities and present value of our reserves. See Business and Properties Proved Reserves for information about our estimated oil and natural gas reserves and the PV-10 and standardized measure of discounted future net cash flows as of December 31, 2006.

In order to prepare our estimates, we must project production rates and timing of development expenditures. We must also analyze available geological, geophysical, production and engineering data. The extent, quality and reliability of this data can vary. The process also requires economic assumptions about matters such as oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds.

Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves most likely will vary from our estimates. Any significant variance could materially affect the estimated quantities and present value of our reserves. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing oil and natural gas prices and other factors, many of which are beyond our control.

For example, our initial well in the Bakken Field was completed in August 2003. As of December 31, 2006, we had 16.4 MMBoe of proved producing reserves assigned to 121 producing wells and 9.2 MMBoe of proved undeveloped reserves assigned to 48 undrilled locations. The Bakken Field contained 22% of our total proved reserves and 30% of our total proved undeveloped reserves as of December 31, 2006. Due to the limited production history of our wells in the Bakken Field, the estimates of future production associated with such properties may be subject to greater variance to actual production than would be the case with properties having a longer production history.

You should not assume that the present value of future net revenues from our proved reserves is the current market value of our estimated oil and natural gas reserves. In accordance with SEC requirements, we generally base the estimated discounted future net cash flows from our proved reserves on prices and costs on the date of the estimate. Actual future prices and costs may differ materially from those used in the present value estimate. If oil prices decline by $1.00 per Bbl, then our PV-10 as of December 31, 2006 would decrease from $1,584 million to $1,536 million. If natural gas prices decline by $0.10 per Mcf, then our PV-10 as of December 31, 2006 would decrease from $1,584 million to $1,582 million.

Our use of enhanced recovery methods creates uncertainties that could adversely affect our results of operations and financial condition.

One of our business strategies is to commercially develop unconventional oil and natural gas resource plays using enhanced recovery technologies. For example, we inject water and high-pressure air into formations on some of our properties to increase the production of oil and natural gas. The additional production and reserves attributable to the use of these enhanced recovery methods are inherently difficult to predict. If our enhanced recovery programs do not allow for the extraction of oil and natural gas in the manner or to the extent that we anticipate, our future results of operations and financial condition could be materially adversely affected.

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Our development and exploitation projects require substantial capital expenditures. We may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a decline in our oil and natural gas reserves.

The oil and natural gas industry is capital intensive. We make and expect to continue to make substantial capital expenditures in our business for the development, exploitation, production and acquisition of oil and natural gas reserves. We invested approximately $326.6 million for capital and exploration expenditures in 2006. Our budgeted capital expenditures for 2007 are expected to increase approximately 34% over the $326.6 million invested during 2006. To date, these capital expenditures have been financed with cash generated by operations and through borrowings from banks and from our principal shareholder. The actual amount and timing of our future capital expenditures may differ materially from our estimates as a result of, among other things, actual drilling results, the availability of drilling rigs and other services and equipment, and regulatory, technological and competitive developments. We intend to finance our future capital expenditures primarily through cash flow from operations and through borrowings under our revolving credit facility; however, our financing needs may require us to alter or increase our capitalization substantially through the issuance of debt or equity securities. The issuance of additional debt will require that a portion of our cash flow from operations be used for the payment of interest and principal on our debt, thereby reducing our ability to use cash flow to fund working capital, capital expenditures and acquisitions. The issuance of additional equity securities could have a dilutive effect on the value of your common stock.

Our cash flow from operations and access to capital are subject to a number of variables, including:

- our proved reserves;
- the level of oil and natural gas we are able to produce from existing wells;
- the prices at which our oil and natural gas are sold; and
- our ability to acquire, locate and produce new reserves.

If our revenues or the borrowing base under our credit facility decrease as a result of lower oil or natural gas prices, operating difficulties, declines in reserves or for any other reason, we may have limited ability to obtain the capital necessary to sustain our operations at current levels. If additional capital is needed, we may not be able to obtain debt or equity financing. If cash generated by operations or cash available under our revolving credit facility is not sufficient to meet our capital requirements, the failure to obtain additional financing could result in a curtailment of our operations relating to development of our prospects, which in turn could lead to a decline in our oil and natural gas reserves, and could adversely affect our business, financial condition and results of operations.

If oil and natural gas prices decrease, we may be required to take write-downs of the carrying values of our oil and natural gas properties.

Accounting rules require that we review periodically the carrying value of our oil and natural gas properties for possible impairment. Based on specific market factors and circumstances at the time of prospective impairment reviews, and the continuing evaluation of development plans, production data, economics and other factors, we may be required to write down the carrying value of our oil and natural gas properties. A write-down constitutes a non-cash charge to earnings. We may incur impairment charges in the future, which could have a material adverse effect on our results of operations for the periods in which such charges are taken.

Unless we replace our oil and natural gas reserves, our reserves and production will decline, which would adversely affect our cash flows and results of operations.

Unless we conduct successful development, exploitation and exploration activities or acquire properties containing proved reserves, our proved reserves will decline as those reserves are produced. Producing oil and

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natural gas reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Our future oil and natural gas reserves and production, and therefore our cash flow and results of operations, are highly dependent on our success in efficiently developing and exploiting our current reserves and economically finding or acquiring additional recoverable reserves. We may not be able to develop, exploit, find or acquire sufficient additional reserves to replace our current and future production. If we are unable to replace our current and future production, the value of our reserves will decrease, and our business, financial condition and results of operations would be adversely affected.

The unavailability or high cost of additional drilling rigs, equipment, supplies, personnel and oilfield services could adversely affect our ability to execute our exploration and development plans within our budget and on a timely basis.

Shortages or the high cost of drilling rigs, equipment, supplies, personnel or oilfield services could delay or cause us to incur significant expenditures that are not provided for in our capital budget, which could have a material adverse effect on our business, financial condition or results of operations.

We may incur substantial losses and be subject to substantial liability claims as a result of our oil and natural gas operations; we may not be insured for, or our insurance may be inadequate to protect us against, these risks.

We are not insured against all risks. Losses and liabilities arising from uninsured and underinsured events could materially and adversely affect our business, financial condition or results of operations. Our oil and natural gas exploration and production activities are subject to all of the operating risks associated with drilling for and producing oil and natural gas, including the possibility of:

- environmental hazards, such as uncontrollable flows of oil, natural gas, brine, well fluids, toxic gas or other pollution into the environment, including groundwater and shoreline contamination;
- abnormally pressured formations;
- mechanical difficulties, such as stuck oilfield drilling and service tools and casing collapse;
- fires, explosions and ruptures of pipelines in connection with our high-pressure air injection operations;
- personal injuries and death; and
- natural disasters.

Any of these risks could adversely affect our ability to conduct operations or result in substantial losses to our company as a result of:

injury or loss of life;

damage to and destruction of property, natural resources and equipment;

pollution and other environmental damage;

regulatory investigations and penalties;

suspension of our operations; and

repair and remediation costs.

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We may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable. The occurrence of an event that is not fully covered by insurance could have a material adverse effect on our business, financial condition and results of operations.

Prospects that we decide to drill may not yield oil or natural gas in commercially viable quantities.

Prospects that we decide to drill that do not yield oil or natural gas in commercially viable quantities will adversely affect our result of operations and financial condition. In this prospectus, we describe some of our current prospects and our plans to explore those prospects. Our prospects are in various stages of evaluation, ranging from a prospect which is ready to drill to a prospect that will require substantial additional seismic data processing and interpretation. There is no way to predict in advance of drilling and testing whether any particular prospect will yield oil or natural gas in sufficient quantities to recover drilling or completion costs or to be economically viable. The use of seismic data and other technologies and the study of producing fields in the same area will not enable us to know conclusively prior to drilling whether oil or natural gas will be present or, if present, whether oil or natural gas will be present in commercial quantities. We cannot assure you that the analogies we draw from available data from other wells, more fully explored prospects or producing fields will be applicable to our drilling prospects.

Our identified drilling locations are scheduled out over several years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling.

Our management has specifically identified and scheduled drilling locations as an estimation of our future multi-year drilling activities on our existing acreage. As of December 31, 2006, we had identified and scheduled 1,772 gross drilling locations. These scheduled drilling locations represent a significant part of our growth strategy. Our ability to drill and develop these locations depends on a number of uncertainties, including oil and natural gas prices, the availability of capital, costs, drilling results, regulatory approvals and other factors. The North Dakota Bakken Shale and Woodford Shale projects comprise 1,417 gross drilling locations. Due to limited production history on the relatively few number of wells drilled in these projects, we are unable to predict with certainty the quantity of future production from wells to be drilled in these projects. If future drilling results in these projects do not establish sufficient reserves to achieve an economic return, we may curtail drilling in these projects. Because of these uncertainties, we do not know if the numerous potential drilling locations we have identified will ever be drilled or if we will be able to produce oil or natural gas from these or any other potential drilling locations. In addition, unless production is established within the spacing units covering the undeveloped acres on which some of the locations are identified, the leases for such acreage will expire. As of December 31, 2006, we had 134,088, 174,169 and 178,399 net acres expiring in 2007, 2008 and 2009, respectively. As such, our actual drilling activities may materially differ from those presently identified, which could adversely affect our business.

Market conditions or operational impediments may hinder our access to oil and natural gas markets or delay our production.

Market conditions or the unavailability of satisfactory oil and natural gas transportation arrangements may hinder our access to oil and natural gas markets or delay our production. The availability of a ready market for our oil and natural gas production depends on a number of factors, including the demand for and supply of oil and natural gas and the proximity of reserves to pipelines and terminal facilities. Our ability to market our production depends in substantial part on the availability and capacity of gathering systems, pipelines and processing facilities owned and operated by third parties. Our failure to obtain such services on acceptable terms could materially harm our business. We may be required to shut in wells due to lack of a market or inadequacy or unavailability of crude oil or natural gas pipeline or gathering system capacity. If that were to occur, then we would be unable to realize revenue from those wells until production arrangements were made to deliver to market.

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We have been an early entrant into new or emerging plays; as a result, our drilling results in these areas are uncertain, and the value of our undeveloped acreage will decline if drilling results are unsuccessful.

While our costs to acquire undeveloped acreage in new or emerging plays have generally been less than those of later entrants into a developing play, our drilling results in these areas are more uncertain than drilling results in areas that are developed and producing. Since new or emerging plays have limited or no production history, we are unable to use past drilling results in those areas to help predict our future drilling results. As a result, our cost of drilling, completing and operating wells in these areas may be higher than initially expected, and the value of our undeveloped acreage will decline if drilling results are unsuccessful.

We are subject to complex federal, state, local, provincial and other laws and regulations that could adversely affect the cost, manner or feasibility of conducting our operations or expose us to significant liabilities.

Our oil and natural gas exploration, production and transportation operations are subject to complex and stringent laws and regulations. In order to conduct our operations in compliance with these laws and regulations, we must obtain and maintain numerous permits, approvals and certificates from various federal, state, local and provincial governmental authorities. We may incur substantial costs in order to maintain compliance with these existing laws and regulations. In addition, our costs of compliance may increase if existing laws and regulations are revised or reinterpreted, or if new laws and regulations become applicable to our operations. Such costs could have a material adverse effect on our business, financial condition and results of operations.

Our business is subject to federal, state, local and provincial laws and regulations as interpreted and enforced by governmental authorities possessing jurisdiction over various aspects of the exploration for, and the production and transportation of, oil and natural gas. Failure to comply with such laws and regulations, as interpreted and enforced, could have a material adverse effect on our business, financial condition and results of operations. See Business and Properties Environmental, Health and Safety Regulation and Business and Properties Regulation of the Oil and Natural Gas Industry for a description of the laws and regulations that affect us.

Strict, joint and several liability may be imposed under certain environmental laws, which could cause us to become liable for the conduct of others or for consequences of our own actions that were in compliance with all applicable laws at the time those actions were taken. In addition, claims for damages to persons or property, including natural resources, may result from our operations.

New laws, regulations or enforcement policies could be more stringent and impose unforeseen liabilities or significantly increase compliance costs. If we were not able to recover the resulting costs through insurance or increased revenues, our business, financial condition or results of operations could be adversely affected.

Competition in the oil and natural gas industry is intense, making it more difficult for us to acquire properties, market oil and natural gas and secure trained personnel.

Our ability to acquire additional prospects and to find and develop reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment for acquiring properties, marketing oil and natural gas and securing trained personnel. Also, there is substantial competition for capital available for investment in the oil and natural gas industry. Many of our competitors possess and employ financial, technical and personnel resources substantially greater than ours. Those companies may be able to pay more for productive oil and natural gas properties and exploratory prospects and to evaluate, bid for and purchase a greater number of properties and prospects than our financial or personnel resources permit. The recent trend in the formation of publicly traded exploration and production master limited partnerships has increased the competition for producing property acquisitions. In addition, companies may be able to offer better compensation packages to attract and retain qualified personnel than we are able to offer. The cost to attract and retain qualified personnel has increased over the past three years due to competition and may

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increase substantially in the future. We may not be able to compete successfully in the future in acquiring prospective reserves, developing reserves, marketing hydrocarbons, attracting and retaining quality personnel and raising additional capital, which could have a material adverse effect on our business.

The loss of senior management or technical personnel could adversely affect operations.

We depend on the services of our senior management and technical personnel. The loss of the services of our senior management or technical personnel, including Harold G. Hamm, our Chairman and Chief Executive Officer, could have a material adverse effect on our operations. We do not maintain, nor do we plan to obtain, any insurance against the loss of any of these individuals.

Terrorist attacks aimed at our energy operations could adversely affect our business.

The continued threat of terrorism and the impact of military and other government action has led and may lead to further increased volatility in prices for oil and natural gas and could affect these commodity markets or financial markets used by us. In addition, the U.S. government has issued warnings that energy assets may be a future target of terrorist organizations. These developments have subjected our oil and natural gas operations to increased risks. Any future terrorist attack on our facilities, those of our customers and, in some cases, those of other energy companies, could have a material adverse effect on our business.

Seasonal weather conditions and lease stipulations adversely affect our ability to conduct drilling activities in some of the areas where we operate.

Oil and natural gas operations in the Rocky Mountains are adversely affected by seasonal weather conditions and lease stipulations designed to protect various wildlife. In certain areas, including parts of Montana, North Dakota, South Dakota, Utah and Wyoming, drilling and other oil and natural gas activities can only be conducted during the spring and summer months. This limits our ability to operate in those areas and can intensify competition during those months for drilling rigs, oilfield equipment, services, supplies and qualified personnel, which may lead to periodic shortages. These constraints and the resulting shortages or high costs could delay our operations and materially increase our operating and capital costs.

Our credit facility contains certain covenants that may inhibit our ability to make certain investments, incur additional indebtedness and engage in certain other transactions, which could adversely affect our ability to meet our future goals.

Our credit facility includes certain covenants that, among other things, restrict:

- our investments, loans and advances and the paying of dividends and other restricted payments;

- our incurrence of additional indebtedness;
- the granting of liens, other than liens created pursuant to the credit facility and certain permitted liens;
- mergers, consolidations and sales of all or substantial part of our business or properties;
- the hedging, forward sale or swap of our production of crude oil or natural gas or other commodities;
- the sale of assets; and
- our capital expenditures.

Our credit facility requires us to maintain certain financial ratios, such as leverage ratios. All of these restrictive covenants may restrict our ability to expand or pursue our business strategies. Our ability to comply with these and other provisions of our credit facility may be impacted by changes in economic or business conditions, results of operations or events beyond our control. The breach of any of these covenants could result in a default under our credit facility, in which case, depending on the actions taken by the lenders thereunder or

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their successors or assignees, such lenders could elect to declare all amounts borrowed under our credit facility, together with accrued interest, to be due and payable. If we were unable to repay such borrowings or interest, our lenders could proceed against their collateral. If the indebtedness under our credit facility were to be accelerated, our assets may not be sufficient to repay in full such indebtedness.

Increases in interest rates could adversely affect our business.

We are exposed to changes in interest rates as a result of borrowings outstanding under our credit facility. After giving effect to this offering and the application of the net proceeds received by us to repay borrowings outstanding under our credit facility, we expect to have total indebtedness outstanding under our credit facility of approximately $129.9 million. The impact of a 1% increase in interest rates on this amount of debt would result in increased interest expense of approximately $1.3 million and a corresponding decrease in our net income.

The inability of our significant customers to meet their obligations to us may adversely affect our financial results.

We are subject to credit risk due to concentration of our crude oil and natural gas receivables with several significant customers. The two largest purchasers of our oil and natural gas during the twelve months ended December 31, 2006 accounted for 19% and 14% of our total oil and natural gas sales revenues. We do not require our customers to post collateral. The inability of our significant customers to meet their obligations to us may adversely affect our financial results.

Risks Relating to the Offering and Our Common Stock

The initial public offering price of our common stock may not be indicative of the market price of our common stock after this offering. In addition, our stock price may be volatile.

Prior to this offering, there has been no public market for our common stock. An active market for our common stock may not develop or may not be sustained after this offering. The initial public offering price of our common stock was determined by negotiations between us, our selling shareholder and representatives of the underwriters, based on numerous factors which we discuss in the Underwriting section of this prospectus. This price may not be indicative of the market price for our common stock after this initial public offering. The market price of our common stock could be subject to significant fluctuations after this offering, and may decline below the initial public offering price. You may not be able to resell your shares at or above the initial public offering price. The following factors could affect our stock price:

- our operating and financial performance and prospects;
- quarterly variations in the rate of growth of our operational and financial indicators, such as net income per share, production, net income and revenues;

- changes in revenue or earnings estimates or publication of reports by equity research analysts;
- speculation in the press or investment community;
- sales of our common stock by us, Harold G. Hamm or other shareholders, or the perception that such sales may occur;
- general market conditions, including fluctuations in commodity prices; and
- domestic and international economic, legal and regulatory factors unrelated to our performance.

The stock markets in general have experienced extreme volatility that has often been unrelated to the operating performance of particular companies. These broad market fluctuations may adversely affect the trading price of our common stock.

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Following this offering, our Chairman and Chief Executive Officer will own approximately 73.2% of our outstanding common stock, giving him influence and control in corporate transactions and other matters, including a sale of our company.

As of the closing of this offering, Harold G. Hamm, our Chairman and Chief Executive Officer, will beneficially own 122,980,608 shares of our outstanding common stock (assuming no exercise of the underwriters overallotment option), representing approximately 73.2% of our outstanding common stock. As a result, Mr. Hamm will continue to be our controlling shareholder and will continue to be able to control the election of our directors, determine our corporate and management policies and determine, without the consent of our other shareholders, the outcome of certain corporate transactions or other matters submitted to our shareholders for approval, including potential mergers or acquisitions, asset sales and other significant corporate transactions. As controlling shareholder, Mr. Hamm could cause, delay or prevent a change of control of our company. The interests of Mr. Hamm may not coincide with the interests of other holders of our common stock.

Several affiliated companies controlled by Mr. Hamm provide oilfield, gathering and processing, marketing and other services to us. We expect these transactions will continue in the future and may result in conflicts of interest between Mr. Hamm s affiliated companies and us. We can provide no assurance that any such conflicts will be resolved in our favor.

Purchasers of common stock in this offering will experience immediate and substantial dilution of $14.27 per share.

Based on an assumed initial public offering price of $17.00 per share, purchasers of our common stock in this offering will experience an immediate and substantial dilution of $14.27 per share in the net tangible book value per share of common stock from the initial public offering price, and our pro forma net tangible book value as of December 31, 2006 was $2.73 per share. See Dilution for a complete description of the calculation of net tangible book value.

The requirements of being a public company, including compliance with the reporting requirements of the Exchange Act and the requirements of the Sarbanes-Oxley Act, may strain our resources, increase our costs and distract management; and we may be unable to comply with these requirements in a timely or cost-effective manner.

As a public company with listed equity securities, we will need to comply with new laws, regulations and requirements, certain corporate governance provisions of the Sarbanes-Oxley Act of 2002, related regulations of the SEC and the requirements of the New York Stock Exchange (NYSE) with which we are not required to comply as a private company. Complying with these statutes, regulations and requirements will occupy a significant amount of time of our board of directors and management and will increase our costs and expenses. We will need to:

- institute a more comprehensive compliance function;
- design, establish, evaluate and maintain a system of internal controls over financial reporting in compliance with the requirements of Section 404 of the Sarbanes-Oxley Act of 2002 and the related rules and regulations of the SEC and the Public Company Accounting Oversight Board;

comply with rules promulgated by the NYSE;

prepare and distribute periodic public reports in compliance with our obligations under the federal securities laws;

establish new internal policies, such as those relating to disclosure controls and procedures and insider trading;

involve and retain to a greater degree outside counsel and accountants in the above activities; and

establish an investor relations function.

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In addition, we also expect that being a public company subject to these rules and regulations will require us to accept less director and officer liability insurance coverage than we desire or to incur substantial costs to obtain coverage. These factors could also make it more difficult for us to attract and retain qualified members of our board of directors, particularly to serve on our audit committee, and qualified executive officers. As a result, compliance with the requirements of the Sarbanes-Oxley Act could have a material adverse effect on our business.

Failure by us to achieve and maintain effective internal control over financial reporting in accordance with the rules of the SEC could harm our business and operating results and/or result in a loss of investor confidence in our financial reports, which could have a material adverse effect on our business and stock price.

We are in the process of evaluating our internal controls systems to allow management to report on, and our independent auditors to audit, our internal controls over financial reporting. We are also in the process of performing the system and process evaluation and testing (and any necessary remediation) required to comply with the management certification and auditor attestation requirements of Section 404 of the Sarbanes-Oxley Act of 2002. We will be required to comply with Section 404 for the year ending December 31, 2008. However, we cannot be certain as to the timing of completion of our evaluation, testing and remediation actions or the impact of the same on our operations. Furthermore, upon completion of this process, we may identify control deficiencies of varying degrees of severity under applicable SEC and Public Company Accounting Oversight Board rules and regulations that remain unremediated. As a public company, we will be required to report, among other things, control deficiencies that constitute a material weakness or changes in internal controls that, or that are reasonably likely to, materially affect internal controls over financial reporting. A material weakness is a significant deficiency or combination of significant deficiencies that results in more than a remote likelihood that a material misstatement of the annual or interim consolidated financial statements will not be prevented or detected. If we fail to implement the requirements of Section 404 in a timely manner, we might be subject to sanctions or investigation by regulatory authorities such as the SEC. In addition, failure to comply with Section 404 or the report by us of a material weakness may cause investors to lose confidence in our consolidated financial statements, and our stock price may be adversely affected as a result. If we fail to remedy any material weakness, our consolidated financial statements may be inaccurate, we may face restricted access to the capital markets and our stock price may be adversely affected.

We will be required to recognize a charge to our earnings related to additional compensation expense associated with our equity compensation plans as a result of this offering.

Our equity compensation plans currently require us to, at a plan participant s request, purchase such participant s vested shares of our restricted stock based on an internally calculated per-share value of our stock. In addition, we currently have the right to purchase vested shares of restricted stock and shares issued upon stock option exercises at the same value from plan participants upon termination of the participant s employment with us for any reason for a period of two years after the termination date. The internal valuation is based on the book value of our shareholders equity adjusted for our PV-10 as of each calendar quarter. Our requirement and right, as applicable, to purchase vested shares of restricted stock and shares issued upon stock option exercises will be eliminated once we begin reporting under Section 12 of the Exchange Act upon completion of this offering. As a result, we will recognize a charge to earnings upon completion of this offering in order to account for the difference between the formula-derived value at which we historically have recognized compensation expense and the initial public offering price. As of December 31, 2006, the charge to earnings would have been $17.4 million, assuming an initial offering price of $17.00 per share (the midpoint of the price range set forth on the cover page of this prospectus). The actual charge to earnings upon completion of the offering will be affected by changes in the formula-derived value and unvested equity awards after December 31, 2006 and the actual initial public offering price. Each $1.00 increase (decrease) in the assumed public offering price per share would increase (decrease) the charge to earnings as of December 31, 2006 by approximately $1.7 million.

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We have no plans to pay dividends on our common stock, and therefore, you may not receive funds without selling your shares.

On January 10, 2007, we declared a cash dividend of approximately $18.8 million to our shareholders and, subject to forfeiture, to holders of unvested restricted stock. On January 31, 2007, we paid $18.7 million of the dividend declared, of which $16.9 million was paid to our principal shareholder. On March 6, 2007, we declared a cash dividend of approximately $33.3 million to our shareholders and, subject to forfeiture, to holders of unvested restricted stock. On April 12, 2007, we paid $33.1 million of the dividend declared, of which $30.0 million was paid to our principal shareholder. We do not anticipate paying any additional cash dividends on our common stock in the foreseeable future. We currently intend to retain future earnings, if any, to finance the expansion of our business. Our future dividend policy is within the discretion of our board of directors and will depend upon various factors, including our business, financial condition, results of operations, capital requirements and investment opportunities.

We are a controlled company within the meaning of NYSE rules and, as a result, we will qualify for, and may rely on, exemptions from certain corporate governance requirements.

Because Harold G. Hamm will beneficially own in excess of 50% of our outstanding shares of common stock after the completion of this offering, he will be able to control the composition of our board of directors and direct our management and policies. We also will be deemed to be a controlled company under the rules of the NYSE. Under these rules, we are not required to comply with certain corporate governance requirements of the NYSE, including:

- the requirement that a majority of our board of directors consist of independent directors;
- the requirement that we have a nominating/corporate governance committee that is composed entirely of independent directors with a written charter addressing the committee s purpose and responsibilities; and
- the requirement that we have a compensation committee that is composed entirely of independent directors with a written charter addressing the committee s purpose and responsibilities.

Following this offering, we may utilize some or all of these exemptions. Accordingly, you may not have the same protections afforded to shareholders of companies that are subject to all of the corporate governance requirements of the NYSE. Mr. Hamm s significant ownership interest could adversely affect investors perceptions of our corporate governance.

Provisions in our organizational documents and under Oklahoma law could delay or prevent a change in control of our company, which could adversely affect the price of our common stock.

We are an Oklahoma corporation. The existence of some provisions in our organizational documents, which we will amend and restate prior to the closing of this offering, and under Oklahoma law could delay or prevent a change in control of our company, which could adversely affect the price of our common stock. The provisions in our amended and restated certificate of incorporation and bylaws that could delay or prevent an unsolicited change in control of our company include a staggered board of directors, board authority to issue preferred stock and advance notice provisions for director nominations or business to be considered at a shareholder meeting. See Description of Capital Stock Anti-Takeover

Effects of Provisions of Our Certificate of Incorporation and Bylaws and of Oklahoma Law.

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Use of Proceeds

We estimate that we will receive net proceeds of $139.6 million from the sale of the 8,850,000 shares of common stock in this offering based upon the assumed initial public offering price of $17.00 per share (the midpoint of the price range set forth on the cover page of this prospectus), after deducting underwriting discounts and estimated offering expenses. Each $1.00 increase (decrease) in the public offering price would increase (decrease) proceeds by approximately $8.3 million. We expect to use the net proceeds of this offering to repay a portion of the borrowings outstanding under our credit facility incurred in connection with recent capital expenditures and cash dividends to our current shareholders. As of April 12, 2007, total borrowings under our credit facility were $269.5 million. Our credit facility has a maturity date in April 2011 and currently bears interest at a rate of 6.71%.

We will not receive any proceeds from the sale of the shares of common stock by the selling shareholder. We estimate that the selling shareholder will receive net proceeds of approximately $330.0 million from the sale of the 20,650,000 shares of our common stock in this offering based upon the assumed initial public offering price of $17.00 per share, after deducting underwriting discounts. We will pay all expenses relating to this offering, other than underwriting discounts related to the shares sold by the selling shareholder. If the underwriters overallotment option to purchase additional shares is exercised in full, we estimate that the selling shareholder s net proceeds will be approximately $400.7 million.

Dividend Policy

On January 10, 2007, we declared a cash dividend of approximately $18.8 million to our shareholders and, subject to forfeiture, to holders of unvested restricted stock. On January 31, 2007, we paid $18.7 million of the dividend declared, of which $16.9 million was paid to our principal shareholder. On March 6, 2007, we declared a cash dividend of approximately $33.3 million to our shareholders and, subject to forfeiture, to holders of unvested restricted stock. On April 12, 2007, we paid $33.1 million of the dividend declared, of which $30.0 million was paid to our principal shareholder. We are currently a subchapter S-corporation under the rules and regulations of the Internal Revenue Service. As a result, income taxes attributable to our federal and state income are payable by our shareholders. The dividends have been paid to shareholders to fund their taxes due and estimated tax payments. In connection with the completion of this offering, we will convert from a subchapter S-corporation to a subchapter C-corporation, and we do not anticipate paying any additional cash dividends on our common stock in the foreseeable future. The selling shareholder has received dividends of approximately $13.5 million, $1.8 million, $79.0 million and $46.9 million in 2004, 2005, 2006 and 2007, respectively. We currently intend to retain future earnings, if any, to finance the expansion of our business. Our future dividend policy is within the discretion of our board of directors and will depend upon various factors, including our results of operations, financial condition, capital requirements and investment opportunities.

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Capitalization

The following table shows our capitalization as of December 31, 2006:

- on a historical basis; and

- on a pro forma basis to reflect our conversion, concurrent with the closing of this offering, from a subchapter S-corporation to a subchapter C-corporation; reclassification of equity compensation accruals; the effect of an 11 for 1 stock split to be effected as a stock dividend prior to the consummation of this offering, the charge to compensation expense to recognize the difference between the initial public offering price of our stock and the value at which compensation expense has been previously recorded and other transactions for which pro forma presentation is necessary in conjunction with this offering and to reflect this offering at an assumed public offering price of $17.00 per share and the application of the net proceeds therefrom as described under Use of Proceeds.

We derived this table from, and it should be read in conjunction with and is qualified in its entirety by reference to, the historical consolidated financial statements and the accompanying notes included elsewhere in this prospectus. You should read this information in conjunction with these consolidated financial statements and Management s Discussion and Analysis of Financial Condition and Results of Operations.

	As of December 31, 2006	
	Historical	**Pro forma**
	(in thousands)	
Cash and cash equivalents(1)	$ 7,018	$ 7,941
Long-term debt, including current maturities(1)	140,000	
Shareholders equity:		
Common stock, $.01 par value; 20,000,000 shares historical, 500,000,000 shares pro forma authorized, 14,464,204 shares historical, 167,956,244 pro forma issued and outstanding(2)	144	1,680
Additional paid-in capital(3)	27,087	390,922
Retained earnings(3)	471,313	65,140
Accumulated other comprehensive loss, net of taxes	(25)	(25)
Total shareholders equity	498,519	457,716
Total capitalization	$ 638,519	$ 457,716

(1) Pro forma adjustment to reflect use of proceeds in connection with this offering to reduce debt with the remainder increasing cash.

(2) Pro forma adjustment to reflect the reclassification of $1.4 million from additional paid-in capital to common stock in order to adjust for the 11 for 1 stock split to be effected as a stock dividend in connection with the consummation of the offering and par value for newly issued shares.

(3) Pro forma adjustments as described in the table below.

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The following table reconciles historical additional paid-in capital and retained earnings to the pro forma amounts:

	Additional Paid-In Capital	Retained Earnings
	(in thousands)	
Historical	$ 27,087	$ 471,313
Underwriting discount	(9,027)	
Reclassification of liability for equity compensation(1)	(14,444)	
Compensation expense(2)		(17,370)
Proceeds of offering	150,362	
Offering costs(3)	(150)	(350)
Deferred taxes on C-corporation conversion(4)		(178,800)
Reclassification of additional paid-in-capital(5)	(1,447)	
Reclassification of undistributed earnings	209,653	(209,653)
Pro forma	$ 390,922	$ 65,140

(1) Pro forma adjustment to reflect the reclassification of the liability for equity compensation to additional paid-in capital.

(2) Pro forma adjustment to show the estimated charge to earnings related to compensation expense that we will recognize upon completion of the offering equal to the difference between the assumed initial public offering price of $17.00 per share (the midpoint of the range set forth on the cover page of this prospectus) and the value at which compensation expense has previously been recorded based on the formula contained in our equity compensation plans. See footnote (2) under Selected Historical and Pro Forma Financial Information

(3) Pro forma adjustment for offering costs not already recognized in historical results. Offering costs consist principally of legal, accounting and printing costs associated with our initial public offering and are estimated to total approximately $1.9 million. Approximately $1.4 million of the costs have already been incurred and reflected in the historical shareholders equity. These costs have been expensed to date because we were not planning to sell stock in the offering. We now intend to sell shares representing approximately 30% of the total offering and will not expense that percentage of offering costs incurred in the future. The balance of offering costs incurred in the future will be expensed.

(4) Pro forma adjustment to charge earnings to recognize deferred taxes upon our conversion from a non-taxable subchapter S-corporation to a taxable subchapter C-corporation.

(5) Pro forma adjustment to reflect the reclassification of $1.4 million from additional paid-in capital to common stock in order to adjust for the 11 for 1 stock split to be effected as a stock dividend in connection with the consummation of this offering.

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Dilution

Dilution is the amount by which the offering price paid by purchasers of common stock sold in this offering will exceed the net tangible book value per share of common stock after the offering. As of December 31, 2006, on a pro forma basis, after giving effect to adjustments to convert from a subchapter S-corporation to a subchapter C-corporation, reclassification of compensation accruals and the charge to compensation expense to recognize the difference between the initial public offering price of our stock and the value at which compensation expense has been previously recorded, our net tangible book value was $316.8 million, or $1.99 per share. After giving effect to the sale of common stock offered by us pursuant to this prospectus (at an assumed offering price of $17.00 per share) and the receipt of the estimated net proceeds, after deducting underwriting discounts and estimated offering expenses, our net tangible book value at December 31, 2006 would have been $2.73 per share. This represents an immediate and substantial increase in the net tangible book value of $0.74 per share to existing shareholders and an immediate dilution of $14.27 per share to new investors purchasing common stock in this offering, resulting from the difference between the offering price and the net tangible book value after this offering. The following table illustrates the per share dilution to new investors who purchase common stock in the offering:

Assumed offering price per share:		$ 17.00
Pro forma net tangible book value per share at December 31, 2006	$ 1.99	
Increase per share attributable to new investors	0.74	
Pro forma net tangible book value per share after this offering		2.73
Dilution per share to new investors		$ 14.27

The following table sets forth, on a pro forma as adjusted basis as of December 31, 2006, the number of shares of common stock purchased from us, the book value of the total consideration paid to us and the book value of the average consideration per share paid to us by our existing shareholders and by the new investors in this offering at an assumed offering price of $17.00 per share (the midpoint of the range set forth on the cover page of this prospectus) after deducting underwriting discounts and estimated offering expenses.

	Shares Issued		Book Value of Total Consideration		Book Value of Average Consideration Per Share
	Number	%	Amount (000s)	%	
New investors	8,850,000	5%	$ 140,923	31%	$ 15.92
Existing shareholders	159,106,244	95%	$ 316,793	69%	$ 1.99
Total	167,956,244	100%	$ 457,716	100%	$ 2.73

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Selected Historical and Pro Forma

Consolidated Financial Information

This section presents our selected historical and pro forma consolidated financial data. The selected historical consolidated financial data presented below is not intended to replace our historical consolidated financial statements.

The following historical consolidated financial data, as it relates to each of the fiscal years ended December 31, 2002 through 2006, has been derived from our audited historical consolidated financial statements for such periods. You should read the following selected historical consolidated financial data in connection with Capitalization, Management s Discussion and Analysis of Financial Condition and Results of Operations and our historical consolidated financial statements and related notes included elsewhere in this prospectus. The selected historical consolidated results are not necessarily indicative of results to be expected in future periods.

The selected pro forma financial data reflect the tax effects of our conversion, concurrent with the closing of this offering, from a subchapter S-corporation to a subchapter C-corporation and the earnings per share impact of our 11 for 1 stock split to be effected in the form of a stock dividend concurrent with the closing of this offering.

	Year ended December 31,				
	2002	2003	2004	2005	2006
	(in thousands, except per share amounts)				
Statement of operations data:					
Revenues:					
Oil and natural gas sales	$ 108,752	$ 138,948	$ 181,435	$ 361,833	$ 468,602
Crude oil marketing and trading(1)	152,092	169,547	226,664		
Oil and natural gas service operations	5,739	9,114	10,811	13,931	15,050
Total revenues	266,583	317,609	418,910	375,764	483,652
Operating costs and expenses:					
Production expense	32,299	40,821	43,754	52,754	62,865
Production tax	7,729	10,251	12,297	16,031	22,331
Exploration expense	10,229	17,221	12,633	5,231	19,738
Crude oil marketing and trading(1)	152,718	166,731	227,210		
Oil and gas service operations	3,485	5,641	6,466	7,977	8,231
Depreciation, depletion, amortization and accretion	29,010	40,256	38,627	49,802	65,428
Property impairments	25,686	8,975	11,747	6,930	11,751
General and administrative(2)	8,668	9,604	12,400	31,266	23,016
(Gain) loss on sale of assets	(223)	(589)	150	(3,026)	(290)
Total operating costs and expenses	$ 269,601	$ 298,911	$ 365,284	$ 166,965	$ 213,070
Income (loss) from operations	$ (3,018)	$ 18,698	$ 53,626	$ 208,799	$ 270,582

Other income (expense)					
Interest expense	(18,216)	(19,761)	(23,617)	(14,220)	(11,310)
Loss on redemption of bonds			(4,083)		
Other	912	295	890	867	1,742
Total other income (expense)	(17,304)	(19,466)	(26,810)	(13,353)	(9,568)

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	Year ended December 31,				
	2002	**2003**	**2004**	**2005**	**2006**
	(in thousands, except per share amounts)				
Income (loss) from continuing operations before income taxes	(20,322)	(768)	26,816	195,446	261,014
Provision (benefit) for income taxes(3)				1,139	(132)
Income (loss) from continuing operations	(20,322)	(768)	26,816	194,307	261,146
Discontinued operations(4)	290	946	1,680		
Loss on sale of discontinued operations(4)			(632)		
Income (loss) before cumulative effect of change in accounting principle	(20,032)	178	27,864	194,307	261,146
Cumulative effect of change in accounting principle(5)		2,162			
Net income (loss)	$ (20,032)	$ 2,340	$ 27,864	$ 194,307	$ 261,146
Basic earnings (loss) per share:					
From continuing operations	$ (1.41)	$ (0.05)	$ 1.87	$ 13.52	$ 18.17
From discontinued operations(4)	0.02	0.06	0.11		
Loss on sale of discontinued operations(4)			(0.04)		
Before cumulative effect of change in accounting principle	(1.39)	0.01	1.94	13.52	18.17
Cumulative effect of change in accounting principle		0.15			
Net income (loss) per share	$ (1.39)	$ 0.16	$ 1.94	$ 13.52	$ 18.17
Shares used in basic earnings (loss) per share	14,369	14,369	14,369	14,369	14,374
Diluted earnings (loss) per share:					
From continuing operations	$ (1.41)	$ (0.05)	$ 1.85	$ 13.42	$ 17.99
From discontinued operations(4)	0.02	0.06	0.12		
Loss on sale of discontinued operations(4)			(0.04)		
Before cumulative effect of change in accounting principle	(1.39)	0.01	1.93	13.42	17.99
Cumulative effect of change in accounting principle		0.15			
Net income (loss) per share	$ (1.39)	$ 0.16	$ 1.93	$ 13.42	$ 17.99
Shares used in diluted earnings (loss) per share	14,369	14,369	14,476	14,482	14,515

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	Year ended December 31,				
	2002	2003	2004	2005	2006
	(in thousands, except per share amounts)				
Pro forma C-corporation and stock split data:					
Income (loss) from continuing operations before income taxes	$ (20,322)	$ (768)	$ 26,816	$ 195,446	$ 261,014
Pro forma provision (benefit) for income taxes attributable to continuing operations	(7,722)	(292)	10,190	74,269	99,185
Pro forma income (loss) from continuing operations	(12,600)	(476)	16,626	121,177	161,829
Discontinued operations, net of tax(4)	180	587	1,042		
Loss on sale of discontinued operations, net of tax(4)			(392)		
Cumulative effect of change in accounting principle, net of tax		1,340			
Pro forma net income (loss)	$ (12,420)	$ 1,451	$ 17,276	$ 121,177	$ 161,829
Pro forma basic earnings (loss) per share	$ (0.08)	$ 0.01	$ 0.11	$ 0.77	$ 1.02
Pro forma diluted earnings (loss) per share	(0.08)	0.01	0.11	0.76	1.01
Other financial data:					
Cash dividends per share:	$	$	$ 1.04	$ 0.14	$ 6.06
EBITDAX (6)	63,288	88,750	116,498	285,344	372,115
Net cash provided by operations	46,997	65,246	93,854	265,265	417,041
Net cash used in investing	(113,295)	(108,791)	(72,992)	(133,716)	(324,523)
Net cash provided by (used in) financing	61,593	43,302	(7,245)	(141,467)	(91,451)
Capital expenditures	113,447	114,145	94,307	144,800	326,579
Balance sheet data at December 31:					
Cash and cash equivalents	$ 2,520	$ 2,277	$ 15,894	$ 6,014	$ 7,018
Property and equipment, net	367,903	439,432	434,339	509,393	751,747
Total assets	406,677	484,988	504,951	600,234	858,929
Long-term debt, including current maturities	247,105	290,920	290,522	143,000	140,000
Shareholders equity	115,081	116,932	130,385	324,730	498,519

(1) Crude oil marketing and trading captions consist of our marketing activities under which crude oil production was sold at the wellhead and transported to a local hub where we purchased the barrels back to exchange at Cushing, Oklahoma in order to minimize pricing differentials with the NYMEX oil futures contract. We adopted Emerging Issues Task Force (EITF) 04-13 on January 1, 2005, which allowed certain purchase and sales transactions with the same counterparty to be combined and accounted for as a single transaction under the guidance of Accounting Principles Board Opinion No. 29. In 2005, we netted $39.8 million of crude oil marketing and trading revenues and $39.7 million of crude oil marketing and trading expenses under oil and natural gas sales. Prior to the adoption of EITF 04-13, we presented crude oil marketing and trading revenues and expenses gross under the guidance provided by EITF 99-19, Reporting Revenues Gross as a Principal and/or Net as an Agent. Effective March 2005, we ceased marketing our crude oil production under these arrangements. Thereafter, we have sold our crude oil at the wellhead. Certain of these sales have been to our affiliates, as described under Certain Relationships and Related Party Transactions.

(2) We have included stock-based compensation of $0.2 million, $0.2 million, $2.0 million, $13.7 million and $2.9 million in general and administrative expenses for the years ended December 31, 2002, 2003, 2004, 2005 and 2006, respectively. Our stock based compensation plans require us to purchase vested shares of restricted stock and shares issued upon the exercise of stock options at the plan participant s request based on an internally calculated value of our stock. In addition, we have the right to purchase vested shares of restricted stock and shares issued upon the exercise of stock options at the same price from plan participants upon termination of the participant s employment with us for any reason for a period of two years after the termination date. Amounts noted herein represent the increase in our liability associated with our purchase obligation. The valuation is based on the book value of our shareholders equity adjusted for our PV-10 as of each calendar quarter. Our requirement and right, as applicable, to purchase vested shares will be eliminated once we begin reporting under Section 12 of the Securities Exchange Act of 1934, as amended (the Exchange Act). As a result of this change, we will recognize a non-cash charge to earnings upon completion of this offering. As of December 31, 2006, the non-cash charge to earnings would have been approximately $17.4 million, assuming an initial offering price of $17.00 per share. See Capitalization.

(3) Properties owned by us at May 31, 1997, the date we converted into a subchapter S-corporation from a subchapter C-corporation, may be subject to federal taxation if sold for an amount in excess of the then tax basis for the sold assets. During 2005, we incurred federal taxes due to the sale of assets acquired prior to May 31, 1997. The benefit recorded during 2006 reflects a change in estimate of the original provision recorded for federal taxes incurred.

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(4) In July 2004, we sold all of the outstanding stock in Continental Gas, Inc., a wholly owned subsidiary, to our shareholders. The Continental Gas, Inc. assets included seven gas gathering systems and three gas-processing plants. These assets represented our entire gas gathering, marketing and processing segment. We have accounted for these operations as discontinued operations.

(5) We adopted Statement of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations and recorded the cumulative effect of the change in accounting principle on January 1, 2003.

(6) EBITDAX represents earnings before interest expense, income taxes (when applicable), depreciation, depletion, amortization and accretion, property impairments, exploration expense and non-cash compensation expense. EBITDAX is not a measure of net income or cash flow as determined by generally accepted accounting principles (GAAP). EBITDAX should not be considered as an alternative to, or more meaningful than, net income or cash flow as determined in accordance with GAAP or as an indicator of a company s operating performance or liquidity. Certain items excluded from EBITDAX are significant components in understanding and assessing a company s financial performance, such as a company s cost of capital and tax structure, as well as the historic costs of depreciable assets, none of which are components of EBITDAX. Our computations of EBITDAX may not be comparable to other similarly titled measures of other companies. We believe that EBITDAX is a widely followed measure of operating performance and may also be used by investors to measure our ability to meet future debt service requirements, if any. Our credit facility requires that we maintain a total debt to EBITDAX ratio of no greater than 3.75 to 1 on a rolling four-quarter basis. Our credit facility defines EBITDAX consistently with the definition of EBITDAX utilized and presented by us. At December 31, 2005 and 2006, this ratio was approximately 0.5 to 1 and 0.4 to 1, respectively. The following table represents a reconciliation of our net income (loss) to EBITDAX:

	Year ended December 31,				
	2002	2003	2004	2005	2006
	(in thousands)				
Net income (loss)	$ (20,032)	$ 2,340	$ 27,864	$ 194,307	$ 261,146
Interest expense	18,216	19,761	23,617	14,220	11,310
Provision (benefit) for income taxes				1,139	(132)
Depreciation, depletion, amortization and accretion	29,010	40,256	38,627	49,802	65,428
Property impairments	25,686	8,975	11,747	6,930	11,751
Exploration expense	10,229	17,221	12,633	5,231	19,738
Equity compensation	179	197	2,010	13,715	2,874
EBITDAX	$ 63,288	$ 88,750	$ 116,498	$ 285,344	$ 372,115

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Management s Discussion and Analysis of Financial Condition and Results of Operations

The following discussion should be read in conjunction with our historical consolidated financial statements and notes, as well as the selected historical consolidated financial data included elsewhere in this prospectus.

Overview

We are engaged in oil and natural gas exploration and exploitation activities in the Rocky Mountain, Mid-Continent and Gulf Coast regions of the United States. Crude oil comprised 83% of our 118.3 MMBoe of estimated proved reserves as of December 31, 2006 and 83% of our 9,018 MBoe of production for the year then ended. We seek to operate wells in which we own an interest, and we operated wells that accounted for 95% of our PV-10 and 82% of our 1,589 gross wells as of December 31, 2006. By controlling operations, we are able to more effectively manage the cost and timing of exploration and development of our properties, including the drilling and fracture stimulation methods used.

Our business strategy has focused on reserve and production growth through exploration and development. For the three-year period ended December 31, 2006, we added 50,421 MBoe of proved reserves through extensions and discoveries, compared to 780 MBoe added through purchases. During this period, our production increased from 5,154 MBoe in 2004 to 9,018 MBoe in 2006. An aspect of our business strategy has been to acquire large undeveloped acreage positions in new or developing resource plays. As of December 31, 2006, we held approximately 1,310,000 gross (738,000 net) undeveloped acres, including 342,000 net acres in the Bakken field in Montana and North Dakota and 162,000 net acres in the New Albany Shale, Lewis Shale, Marfa Basin and Woodford Shale projects. As an early entrant in new or emerging plays, our costs to acquire undeveloped acreage have generally been less than those of later entrants into a developing play. As an example of the cost advantage of entering a play early, our per acre costs for our lease acquisitions in the North Dakota Bakken field during 2003 and 2004 were approximately 80% lower than the per acre costs paid by third parties and by us in the federal and state lease auctions for acreage near our holdings in that area during 2005. However, as an early entrant, we are exposed to the risk that the value of our undeveloped acreage is diminished by unsuccessful drilling results.

How We Evaluate Our Operations

We use a variety of financial and operational measures to assess our performance. Among these measures are the following:

(1) Volumes of oil and natural gas produced;

(2) Oil and natural gas prices realized;

(3) Volumetric operating and administrative costs; and

(4) EBITDAX.

Volumes of Oil and Natural Gas Produced

For our operated properties in the Red River units and the Bakken field, we receive daily production estimates that enable us to monitor our production on a current basis. We believe the timeliness of this information and the control we exert as an operator enables us to respond promptly to production difficulties. Over the past three years our equivalent production volumes have increased 75% or 3,864 MBoe due primarily to

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a 103% increase in oil production. The following table presents our production volumes for each of the three years ended December 31, 2006:

	Year Ended December 31,			Three-year period	
	2004	2005	2006	Volume increase (decrease)	Percent increase (decrease)
MBbls	3,688	5,708	7,480	3,792	103%
MMcf	8,794	9,006	9,225	431	5%
MBoe	5,154	7,209	9,018	3,864	75%

The increase in our production has been the result of a favorable response to additional field development and enhanced recovery efforts in our Red River units coupled with exploration and development within our other producing areas, primarily the Montana Bakken field.

Oil and Natural Gas Prices Realized

We market our oil and natural gas production to a variety of purchasers based on regional pricing. A significant portion of our oil and natural gas production has been marketed to affiliates as discussed under Certain Relationships and Related Party Transactions.

The following table presents the NYMEX oil and natural gas prices, our realized oil and natural gas prices, exclusive of the effects of hedging, and the differences for each of the three years ended December 31, 2006. The NYMEX oil price was determined each month as the calendar month average of the prompt NYMEX crude oil futures contract price and, the NYMEX natural gas price, as the average of the last three trading days of the prompt NYMEX natural gas futures contract price. The NYMEX natural gas futures contract price is quoted on an MMBtu basis. For purposes of comparison, in the table below, the NYMEX natural gas price was converted to an Mcf basis at a one-to-one conversion:

	Year ended December 31,		
	2004	2005	2006
NYMEX oil price ($/Bbl)	$ 41.95	$ 57.69	$ 66.34
Realized oil price before hedging ($/Bbl)	38.85	52.45	55.30
Difference	$ 3.10	$ 5.24	$ 11.04
NYMEX natural gas price ($/Mcf)	$ 6.10	$ 8.54	$ 7.24

Realized natural gas price ($/Mcf)	5.06	6.93	6.08
Difference	$ 1.04	$ 1.61	$ 1.16

The differences are subject to variability due to quality and location pricing fluctuations caused by localized supply and demand fundamentals and transportation availability. The increase in the difference between the NYMEX oil price and our realized oil price during 2006 was attributable to higher oil imports and production in the Rocky Mountain region, lower demand by local Rocky Mountain refineries due to downtime for maintenance and reduced seasonal demand for gasoline and downstream transportation capacity constraints. We are unable to predict when, or if, the difference will revert back to pre-2006 levels.

Our revenues and net income are sensitive to oil and natural gas prices. A $1.00 per Bbl change in realized oil prices would change our reported 2006 revenues and net income by approximately $7.5 million and $7.1 million, respectively. Similarly, a $0.10 per Mcf change in realized natural gas prices would change our reported 2006 revenues and net income by approximately $923,000 and $879,000, respectively.

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For the year ended December 31, 2004, we realized oil hedging losses of $6.4 million. As a result of our limited bank borrowings and strong operational cash flows, we did not enter into any hedges for our 2005 and 2006 production, and we do not currently have plans to hedge any of our 2007 production.

Volumetric Operating and Administrative Costs

Two other measures that we monitor and analyze are production expense per Boe sold and general and administrative expense per Boe sold. We believe these are important measures because they are indicators of operating cost efficiency.

The following table presents our production expense and general and administrative expense, inclusive of stock-based compensation, per Boe sold for each of the three years ended December 31, 2006:

	Year ended December 31,		
	2004	**2005**	**2006**
Production expense ($/Boe)	$ 8.49	$ 7.32	$ 6.99
General and administrative expense ($/Boe)	2.41	4.34	2.56

Our per unit production expense was higher during 2004 due to the start of our enhanced recovery project in the Red River units which initially lowered volumes and increased production expense. Our per unit production expense declined in 2005 and 2006 as we are experiencing higher production volumes due to continued drilling and higher production in conjunction with the completion of the enhanced recovery program. Generally as production increases, we will see increased production expense due to additional well costs, such as lifting and workover costs, and additional personnel costs although these costs may be lower on a volumetric basis due to higher production. The increase in our per unit general and administrative expense in 2005 was primarily due to higher compensation expense. The largest component of the increase was equity compensation, which contributed $2.0 million, $13.7 million and $2.9 million during the years ended December 31, 2004, 2005 and 2006, respectively. The annual increases in equity compensation through 2005 were attributable to additional equity grants and a higher per share valuation resulting from annual increases in our PV-10. The decline in equity compensation during 2006 was attributable to a lower per share valuation resulting from a decline in our PV-10 valuation due to lower oil and natural gas commodity prices as of December 31, 2006 compared to December 31, 2005. We compete with other companies for personnel, particularly in the operational and technical (engineering and geologic) aspects of our business. To remain competitive, we compare the compensation we pay our employees to that of our competitors through surveys, employee feedback and other means. We have experienced higher compensation expense due to competitive pressures, normal merit increases and incentive compensation. Our incentive compensation for 2004 was $413,000 compared to $4.0 million in 2005 and $2.9 million in 2006.

EBITDAX

We calculate and define EBITDAX as net income before interest expense, income taxes (when applicable), depreciation, depletion, amortization and accretion, property impairments, exploration expense and non-cash compensation expense. EBITDAX is used as a financial measure by our management team and by other users of our consolidated financial statements such as our commercial bank lenders, investors, research analysts and others to assess:

- Our operating performance and return on capital in comparison to other independent exploration and production companies, without regard to financial or capital structure;

- The financial performance of our assets and valuation of the entity without regard to financing methods, capital structure or historical cost basis; and

- Our ability to generate cash sufficient to pay interest costs and support our indebtedness.

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The following table presents our EBITDAX for each of the three years ended December 31, 2006 (in thousands):

	Year ended December 31,		
	2004	**2005**	**2006**
EBITDAX	$ 116,498	$ 285,344	$ 372,115

EBITDAX is a financial measure that is reported to our lenders each calendar quarter. Our credit facility requires that our total debt to EBITDAX ratio be no greater than 3.75 to 1 on a rolling four quarter basis. This ratio was 0.4 to 1 at December 31, 2006. Our credit facility defines EBITDAX consistently with the definition of EBITDAX utilized and presented by us. EBITDAX is not and should not be considered as an alternative to net income, operating income, cash flows from operating activities or any other measure of financial performance presented in accordance with GAAP. For a reconciliation of our consolidated net income to EBITDAX, see footnote (5) to Summary Historical and Pro Forma Consolidated Financial Data.

Recent Events

Cash Dividends. On January 10, 2007, we declared a cash dividend of approximately $18.8 million, to our shareholders and, subject to forfeiture, to holders of unvested restricted stock. On January 31, 2007, we paid $18.7 million of the dividend declared, of which $16.9 million was paid to our principal shareholder. On March 6, 2007, we declared a cash dividend of approximately $33.3 million to our shareholders of record and, subject to forfeiture, to holders of unvested restricted stock. On April 12, 2007, we paid $33.1 million of the dividend declared, of which $30.0 million was paid to our principal shareholder. We are currently a subchapter S-corporation under the rules and regulations of the Internal Revenue Service. As a result, income taxes attributable to our federal and state income are payable by our shareholders. The dividends have been paid to shareholders to fund their taxes due and estimated tax payments and not in connection with our contemplated initial public offering or conversion to a subchapter C-corporation. Upon the consummation of this offering, we will have more shareholders than the IRS rules and regulations governing S-corporations allow and, therefore, we will convert automatically from a subchapter S-corporation to a subchapter C-corporation. In connection with this conversion, we will record a charge to earnings (estimated to be approximately $178.8 million if the conversion had occurred on December 31, 2006) to recognize deferred taxes. We do not anticipate paying any additional cash dividends on our common stock in the foreseeable future.

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Results of Operations

The following tables present selected financial and operating information for each of the three years ended December 31, 2006:

	Year ended December 31,		
	2004	**2005**	**2006**
	(in thousands, except price data)		
Oil and natural gas sales	$ 181,435	$ 361,833	$ 468,602
Total revenues(1)	418,910	375,764	483,652
Operating costs and expenses(1)	365,284	166,965	213,070
Other expense	(26,810)	(13,353)	(9,568)
Income from continuing operations before income taxes	26,816	195,446	261,014
Provision for income taxes		1,139	(132)
Income from continuing operations	26,816	194,307	261,146
Discontinued operations	1,680		
Loss on sale of discontinued operations	(632)		
Net income	$ 27,864	$ 194,307	$ 261,146
Sales volumes:			
Oil (MBbl)(2)	3,688	5,708	7,459
Natural gas (MMcf)	8,794	9,006	9,225
Oil equivalents (MBoe)	5,154	7,209	8,997
Average prices(2):			
Oil, without hedges ($/Bbl)	$ 38.85	$ 52.45	$ 55.30
Oil, with hedges ($/Bbl)	37.12	52.45	55.30
Natural gas ($/Mcf)	5.06	6.93	6.08
Oil equivalents, without hedges ($/Boe)	36.45	50.19	52.09
Oil equivalents, with hedges ($/Boe)	35.20	50.19	52.09

(1) Revenues for 2004 include $226,664,000 for crude oil marketing and trading, and operating expenses include $227,210,000 for crude oil marketing and trading.

(2) Oil sales volumes are 21 MBbls less than oil production volumes for the year ended 2006. Average prices have been calculated using sales volumes.

Year Ended December 31, 2006 Compared to the Year Ended December 31, 2005

Revenues.

Oil and natural gas sales. Oil and natural gas sales for the year ended December 31, 2006 were $468.6 million, a 30% increase over sales of $361.8 million for the comparable period of 2005. Increased sales resulted from additional sales volumes, which increased 25%, and an increase of $1.90 in our realized price per Boe from $50.19 to $52.09. During 2006, we experienced an increase in the differential between NYMEX prices and our realized crude oil prices. The differential per barrel for the twelve months ended December 31, 2006 was $11.04 as compared to $5.24 for the comparable period of 2005. We realized a crude oil differential in December 2006 of $13.32 per Bbl compared to a high of $14.25 per Bbl in March 2006. Among the factors contributing to the higher differentials were higher Canadian oil imports, increases in production in the Rocky Mountain region, refinery downtime in the Rocky Mountain region, downstream transportation capacity constraints, and reduced seasonal demand for gasoline. We are unable to predict when, or if, the differential will revert back to pre-2006 levels.

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The following tables reflect our production by product and region for the periods presented.

	Year ended December 31,				
	2005		2006		
	Volume	Percent	Volume	Percent	Percent increase
Oil (MBbl)(1)	5,708	79%	7,480	83%	31%
Natural Gas (MMcf)	9,006	21%	9,225	17%	2%
Total (MBoe)	7,209	100%	9,018	100%	25%

	Year ended December 31,				
	2005		2006		
	MBoe	Percent	MBoe	Percent	Percent increase (decrease)
Rocky Mountain	5,410	75%	7,159	79%	32%
Mid-Continent	1,361	19%	1,497	17%	10%
Gulf Coast	438	6%	362	4%	(17)%
Total MBoe	7,209	100%	9,018	100%	25%

(1) Oil sales volumes are 21 MBbls less than oil production volumes for the year ended December 31, 2006.

Oil production volumes increased 31% during the year ended December 31, 2006 in comparison to the year ended December 31, 2005. Production increases in the Bakken field contributed incremental volumes in excess of 2005 levels of 815 MBbls, and the Red River units contributed 865 MBbls of incremental production. Initial production commenced in the Bakken field in August 2003 and has increased thereafter, as we have continued exploration and development activities within the field. Favorable results from the enhanced recovery program and additional field development have been the primary contributors to production growth in the Red River units.

Oil and Natural Gas Service Operations. Our oil and natural gas service operations consist primarily of sales of high-pressure air and the treatment and sale of lower quality crude oil, or reclaimed oil. We initiated the sale of high-pressure air from our Red River units to a third party in 2004 and recorded revenues of $3.1 million during 2006 and $3.0 million during 2005. Higher prices for reclaimed oil sold from our central treating unit in 2006 increased oil and natural gas service operations revenues by $0.8 million to $9.4 million at year end 2006. Associated oil and natural gas service operations expenses increased $0.2 million to $8.2 million during the year ended December 31, 2006 from $8.0 million during 2005 due mainly to an increase in the costs of purchasing and treating oil for resale.

Operating Costs and Expenses

Production Expense and Tax. Production expense increased $10.1 million or 19% during the year ended December 31, 2006 to $62.9 million from $52.8 million during the year ended December 31, 2005. The increase in 2006 was due to increases of $3.8 million in workovers, $1.4 million in energy and chemical costs, $1.5 million in repairs, $1.1 million in overhead, $0.6 million in outside operated well costs, $0.5 million in saltwater disposal expenses, $0.4 million in contract labor costs, and as a result of new wells drilled.

Production taxes increased $6.3 million during the year ended December 31, 2006 to $22.3 million from $16.0 million during 2005. The majority of the production tax increase was $5.9 million in the Rocky Mountain region. Production tax as a percentage of oil and natural gas sales was 4.4% for the year ended December 31, 2005 compared to 4.8% for the year ended December 31, 2006. Production taxes are based on the wellhead values of production and vary by state. Additionally, some states offer exemptions or reduced production tax rates for wells that produce less than a certain quantity of oil or gas and to encourage certain activities, such as horizontal drilling and enhanced recovery projects. In Montana, new horizontal wells qualify for a tax incentive and are taxed at 0.76% during the first 18 months of production. After the 18 month incentive period expires, the tax rate increases to 9.26%. In 2006, 33 new producing wells were added in Montana at a tax rate of 0.76% and 21 wells reached the end of their exemption period and their tax rate was increased to 9.26%. Also in the Rocky Mountain region, 8 wells were added in North Dakota at a rate of 11.5%. As production tax incentives we currently receive for horizontal wells in Montana continue to reach the end of the 18 month incentive period, our overall rate is expected to increase.

On a unit of sales basis, production expense and production taxes were as follows:

	Year ended December 31,		Percent increase (decrease)
	2005	2006	
Production expense ($/Boe)	$ 7.32	$ 6.99	(5)%
Production tax ($/Boe)	2.22	2.48	12%
Production expense and tax ($/Boe)	$ 9.54	$ 9.47	(1)%

Exploration Expense. Exploration expenses consist primarily of dry hole costs and exploratory geological and geophysical costs that are expensed as incurred. Exploration expenses increased $14.5 million in 2006 to $19.7 million due primarily to an increase in dry hole expense of $11.9 million and an increase in seismic expenses of $2.0 million. The Rocky Mountain region contributed 54% of the dry hole costs, 24% was in the Mid-Continent region and the remaining 22% was in the Gulf Coast region. The increase in dry hole expense was due to a higher level of drilling during 2006. Exploration capital expenditures were $68.7 million in 2006 compared to $9.3 million in 2005.

Depreciation, Depletion, Amortization and Accretion (DD&A.) DD&A on oil and gas properties increased $15.3 million in 2006 due to increased production and additional properties being added through our drilling program. The DD&A rate on oil and gas properties for 2005 was $6.50 per Boe compared to $6.91 per Boe for 2006. Accretion expense increased $0.1 million to $1.7 million during 2006 from $1.6 million during 2005.

Property Impairments. Property impairments increased during 2006 by $4.9 million to $11.8 million compared to $6.9 million for 2005. Non-producing properties consist of undeveloped leasehold costs and costs associated with the purchase of certain proved undeveloped reserves. Individually significant non-producing properties are periodically assessed for impairment of value and a loss is recognized at the time of impairment by providing an impairment allowance. Other non-producing properties are amortized on a composite method based on our estimated experience of successful drilling and the average holding period. Impairment of non-producing properties increased $1.0 million during 2006 to $5.4 million compared to $4.4 million for 2005.

Impairment provisions for developed oil and gas properties were approximately $2.5 million for the year ended December 31, 2005 and $6.3 million for the year ended December 31, 2006. The increase in 2006 impairment expense resulted primarily from developmental well dry holes and properties where the associated field level reserves were not sufficient to recover capitalized drilling and completion costs.

General and Administrative Expense. General and administrative expense decreased primarily due to a $10.8 million decrease in equity compensation expense net of a charge of $1.5 million associated with our President s non-equity compensation plan as described under Management Summary Compensation Table, associated with restricted stock grants and stock options under our long-term incentive plans. The decrease in equity compensation was attributable to lower per share value for our equity as a result of a decline in our PV-10 value due to lower oil and gas prices in the last half of 2006. On a volumetric basis, general and administrative expense was $2.56 per Boe for 2006 compared to $4.34 per Boe for 2005. We have granted stock options and restricted stock to our employees. The terms of the grants require that, while we are a private company, we are required to purchase vested options and restricted stock at each employee s request at a per share amount derived from our shareholders equity value adjusted quarterly for our PV-10. The obligation to purchase the options is eliminated in the event we become a reporting company under Section 12 of the Exchange Act.

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Gain on Sale of Assets. During 2005, we realized a gain of $6.1 million on the sale of oil and gas wells and a loss of $3.1 million on the termination of compressor capital leases. Gains in 2006 amounted to approximately $0.3 million on miscellaneous asset sales.

Interest Expense. Interest expense decreased 20% for 2006 due to a lower average outstanding debt balance on our credit facility of $156.6 million compared to $184.0 million for 2005 even though the weighted average interest rate on our credit facility was 6.36% for the year ended December 31, 2006 compared to 5.10% for the year ended December 31, 2005. Additionally, in 2005, we had an outstanding balance due to our principal shareholder for $48.0 million which was paid in full during December 2005. We paid $2.9 million in interest on this note during 2005 at a rate of 6%.

Year Ended December 31, 2005 Compared to Year Ended December 31, 2004

Revenues

Oil and Natural Gas Sales. Oil and natural gas sales increased $180.4 million or 99% to $361.8 million in 2005. The increase was attributable to higher production volumes and higher oil and natural gas prices. During 2004, our average wellhead oil price was $38.85 per Bbl and our wellhead natural gas price was $5.06 per Mcf, compared to $52.45 per Bbl for oil and $6.93 per Mcf for natural gas during 2005. The increases in our wellhead prices were due to general industry price escalations in our producing regions. Our oil sales in 2004 were reduced by a $6.4 million loss in our hedging activities. We did not hedge our production during 2005. The following tables reflect our production by product and region for the periods presented:

	Year ended December 31,				
	2004		2005		
	Volume	Percent	Volume	Percent	Percent increase
Oil (MBbl)	3,688	72%	5,708	79%	55%
Natural Gas (MMcf)	8,794	28%	9,006	21%	2%
Total (MBoe)	5,154	100%	7,209	100%	40%

	Year ended December 31,				
	2004		2005		
	MBoe	Percent	MBoe	Percent	Percent increase (decrease)
Rocky Mountain	3,279	64%	5,410	75%	65%
Mid-Continent	1,461	28%	1,361	19%	(7)%
Gulf Coast	414	8%	438	6%	6%

Total MBoe	5,154	100%	7,209	100%	40%

Production increases in our Bakken field and Red River units in the Rocky Mountain region of 1,226 MBoe and 1,051 MBoe, respectively, accounted for the growth in production for 2005. We commenced drilling our initial well in the Bakken field in May 2003 and completed it as a producing well in August 2003. Our well count in the Bakken field rose from 25 gross (14.5 net) wells at December 31, 2004 to 60 gross (34.2 net) wells at December 31, 2005. Favorable response to the enhanced recovery program was the primary factor in the production growth in the Red River units.

Crude Oil Marketing and Trading. During 2004 and the first three months of 2005, we purchased barrels back from certain of our wellhead purchasers downstream of the initial sales point to exchange at the Cushing, Oklahoma hub in order to minimize pricing differentials with the NYMEX oil futures contract. In 2005, revenues of $39.8 million and expenses of $39.7 million pertaining to these marketing activities were netted as provided by Emerging Issues Task Force (EITF) 04-13, which we adopted as of January 1, 2005. We presented these purchase and sale activities gross in the 2004 income statement as crude oil marketing and trading revenues of

$226.7 million and crude oil marketing and trading expenses of $227.2 million under the guidance provided by EITF 99-19, Reporting Revenues Gross as a Principal and/or Net as an Agent. We ceased marketing our production in this manner in March 2005 and now generally market our production at the wellhead.

Oil and Natural Gas Service Operations. Our oil and natural gas service operations consist primarily of sales of high-pressure air and the treatment and sale of lower quality crude oil (reclaimed oil). We initiated the sale of high-pressure air from our Red River units to a third party in 2004, and recorded revenues of $2.0 million and $3.0 million during 2004 and 2005, respectively. Higher prices for reclaimed oil sold from our central treating unit in 2005 increased oil and natural gas service operations revenues by $2.2 million to $8.8 million. Associated oil and natural gas service operations expenses increased $2.0 million from 2004 compared to 2005 due principally to an increase in the costs of purchasing and treating oil for resale.

Operating Costs and Expenses

Production Expense and Tax. Our production expense increased $9.0 million or 21%. This increase was primarily due to production expense associated with the 80 gross (45.4 net) productive wells drilled during 2005, industry inflation and higher energy costs in the Red River units. On a unit of production basis, production expense fell from $8.49 per Boe in 2004 to $7.32 per Boe in 2005.

Energy costs in the Red River units increased $3.0 million to $9.9 million in 2005. The increased energy costs were mainly due to higher electrical costs, resulting from higher production volumes, to run compressors for the high-pressure air injection and other enhanced recovery operations in the field. Workovers in this field also increased from $0.2 million in 2004 to $1.8 million in 2005.

Production tax increased $3.7 million or 30% in 2005 compared to the 99% increase in oil and gas sales. As a percentage of oil and natural gas revenues, production tax was 4.4% in 2005 compared to 6.8% in 2004. In the state of Montana, a horizontal well qualifies for a 0.76% production tax rate on oil and natural gas sales for the first 18 months of production. Thereafter, the production tax rate is 9.26%. All of the wells we drilled in the Montana Bakken field qualified for the reduced production tax rate.

Our oil and natural gas revenues from the Montana Bakken field increased to approximately $93.3 million in 2005 from $19.1 million in the prior year. The addition of approximately $74.2 million in oil and gas revenues at a 0.76% production tax rate was the principal reason production tax increased 30% compared to the 99% increase in oil and gas sales.

On a unit of sales basis, production expense and production tax were as follows:

	Year ended December 31,		
	2004	**2005**	**Percent decrease**

Production expense ($/Boe)	$ 8.49	$ 7.32	(14)%
Production tax ($/Boe)	2.39	2.22	(7)%
Production expense and tax ($/Boe)	$ 10.88	$ 9.54	(12)%

Exploration Expense. Exploration expense decreased from 2004 to 2005 as a result of a reduction primarily in our dry hole expense from $9.5 million in 2004 to $1.4 million in 2005. The higher dry hole expense during 2004 was primarily attributable to dry holes in the Gulf Coast region with a higher per well cost.

Depreciation, Depletion, Amortization and Accretion (DD&A). The DD&A rate per Boe decreased from $7.02 per Boe in 2004 to $6.50 per Boe in 2005. The reduction in the DD&A rate per Boe was mainly due to the addition of 32,427 MBoe of proved reserves during 2005. The amount of DD&A attributable to oil and gas properties increased by $10.6 million in 2005 due to increased production volumes. Accretion expense associated with our asset retirement obligations was $1.0 million and $1.6 million in 2004 and 2005, respectively.

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Property Impairments. We evaluate our properties on a field-by-field basis, as may be necessary, when facts and circumstances such as downward reserve revisions or lower oil and natural gas prices indicate that their carrying amounts may not be recoverable. We recorded a $6.2 million impairment in 2004 compared to a $2.5 million impairment in 2005 on producing properties. The decrease from 2004 to 2005 was due to higher impairment charges on Gulf Coast region properties during 2004. We also evaluate our undeveloped leasehold cost and adjust the acreage valuation quarterly based on our assessment of the potential for the acreage to be developed and the market value of the acreage. Undeveloped leasehold cost is expensed over the life of the lease or transferred to the associated producing properties. Individually significant non-producing properties are periodically assessed for impairment of value and a loss is recognized if necessary. During 2004 we impaired $5.5 million of undeveloped leasehold cost compared to $4.4 million during 2005.

General and Administrative Expense. The majority of the increase in general and administrative expense for 2005 was the result of higher wages and bonuses paid to our employees. The number of employees increased from 275 at year-end 2004 to 286 at year-end 2005, which, combined with salary adjustments and cash bonus increases, increased payroll and other employee-related expenses by $5.3 million during 2005. On a volumetric basis, our general and administrative expense, including equity compensation of $2.0 million and $13.7 million, respectively, was $2.41 per Boe and $4.34 per Boe for the years ended December 31, 2004 and 2005, respectively.

Equity compensation expense increased from $2.0 million in 2004 to $13.7 million in 2005 primarily due to additional equity grants and a higher per share valuation resulting from the increase in our PV-10.

Interest Expense. Interest expense declined from $23.6 million in 2004 to $14.2 million in 2005. The decline in interest expense was attributable to a lower average bank indebtedness during 2005. At December 31, 2004, we had $230.0 million outstanding on our bank credit facility with an effective interest rate of 4.36% compared to $143.0 million outstanding at December 31, 2005, with an effective interest rate of 6.08%. We incurred $6.8 million and $9.3 million in interest on our credit facility in 2004 and 2005, respectively. On November 22, 2004, we signed a note with our principal shareholder for $50.0 million due March 31, 2008. The annual rate of interest was 6.00% and interest payments were due on the last day of each calendar quarter beginning December 31, 2004. We paid $308,000 and $2.9 million in interest in 2004 and 2005, respectively on this note to our principal shareholder. In December 2005, we paid the note in full to our principal shareholder. During November 2004, we utilized available borrowing capacity under our credit facility to redeem $119.5 million of our outstanding Senior Subordinated 10.25% Notes and paid a premium of $4.1 million due on the early redemption of the Notes. Total interest expense on the Senior Subordinated Notes during 2004 was $11.4 million.

Provision for Income Taxes. We recognized income tax expense of $1.1 million during the three months ended March 31, 2005 in connection with the sale of assets acquired prior to our conversion to a subchapter S-corporation from a subchapter C-corporation on May 31, 1997. These assets had Built in gains, as defined by Section 1374 of the Internal Revenue Code, which resulted in a taxable event for us.

Discontinued Operations. In July 2004, we completed the sale of all of the outstanding stock in Continental Gas Inc. (CGI) to our shareholders for $22.6 million in cash. The sales price was representative of the fair value of the net assets based on an appraisal by an independent third party who also provided us with an opinion of the fairness from a financial point of view, of the sale of CGI to the shareholders. The CGI assets included seven natural gas gathering systems and three natural gas-processing plants. These assets represented our entire natural gas gathering, marketing and processing segment and have been classified as discontinued operations for all periods presented.

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Liquidity and Capital Resources

Our primary sources of liquidity have been cash flows generated from operating activities and financing provided by our bank credit facility and principal shareholder. In November 2004, we signed a note with our principal shareholder for $50 million due March 31, 2008. In January 2005, our principal shareholder contributed $2.0 million of the previously loaned amount to us. We paid the $48.0 million outstanding balance due on the note in December 2005. We believe that funds from operating cash flows and the bank credit facility should be sufficient to meet our cash requirements inclusive of, but not limited to, normal operating needs, debt service obligations, planned capital expenditures, and commitments and contingencies for the next 12 months. We intend to fund our longer term cash requirements beyond 12 months through operating cash flows, commercial bank borrowings and access to equity and debt capital markets. Although our longer term needs may be impacted by factors discussed in the section entitled Risk Factors, such as declines in oil and natural gas prices, drilling results, ability to obtain needed capital on satisfactory terms, and other risks which could negatively impact production and our results of operations, we currently anticipate that we will be able to generate or obtain funds sufficient to meet our long-term cash requirements. During 2006, we declared cash dividends totaling $87.6 million to existing shareholders and, subject to forfeiture, to holders of unvested restricted stock. Of this amount, $298,000 was charged to compensation expense related to the restricted stock liability. During 2006, we paid cash dividends of $87.4 million. The unpaid balance of $218,000 relates to dividends associated with unvested restricted stock and will be paid as the restricted stock vests. On January 10, 2007, we declared a cash dividend of approximately $18.8 million to our shareholders for tax purposes and, subject to forfeiture, to holders of unvested restricted stock. On January 31, 2007, we paid $18.7 million of the dividend declared. On March 6, 2007, we declared a cash dividend of approximately $33.3 million payable in April 2007 to our shareholders of record as of March 15, 2007, for tax purposes and, subject to forfeiture, to holders of unvested restricted stock. In connection with the completion of this offering, we will convert from a subchapter S-corporation to a subchapter C-corporation, and we do not anticipate paying any additional cash dividends on our common stock in the foreseeable future. At December 31, 2005 and 2006, we had cash and cash equivalents of $6.0 million and $7.0 million, respectively, and available borrowing capacity on our credit facility of $107.0 million and $160.0 million, respectively.

Cash Flow from Operating Activities

Our net cash provided by operating activities was $93.9 million, $265.3 million and $417.0 million for the years ended December 31, 2004, 2005 and 2006, respectively. The increases in operating cash flows in 2005 and 2006 were principally due to increased production and higher oil and natural gas prices. Additionally, hedging losses were $6.4 million in 2004. There were no hedges in place during 2005 and 2006.

Cash Flow from Investing Activities

During the years ended December 31, 2004, 2005 and 2006 we invested $94.3 million, $144.8 million and $326.6 million, respectively, in our capital program, inclusive of dry hole and seismic costs. The increases in our capital program in 2005 and 2006 were due to the implementation of enhanced recovery and increased density drilling in our Red River units and additional exploration and development drilling.

Cash Flow from Financing Activities

Net cash used in financing activities was $7.2 million for 2004, $141.5 million for 2005 and $91.5 million for 2006. In 2004, cash used in financing activities was primarily attributable to the repurchase of our Senior Subordinated Notes. In 2005, cash used in financing activities was primarily attributable to the repayment of long-term debt. During 2006, cash used in financing activities was primarily attributable to the payment of cash

dividends. Our long-term debt, including the current portion and capital leases, was $290.5 million, $143.0 million and $140.0 million at December 31, 2004, 2005 and 2006, respectively.

Credit Facility

We had $143.0 million and $140.0 million outstanding under our bank credit facility at December 31, 2005 and 2006, respectively. During 2006, capital expenditures of $326.6 million and dividends of $87.4 million were funded principally by $417.0 million in cash provided by operating activities, which benefited from an increase of $77.4 million in our accounts payable trade for the year ended December 31, 2006. As of April 12, 2007, the amount outstanding under our credit facility has increased by $129.5 million to $269.5 million. The increase is largely due to borrowings to fund cash dividends of approximately $52.0 million paid in 2007 and borrowings for the reduction in our accounts payable trade balance which had increased by $50.4 million in the fourth quarter due to the increase in our fourth quarter capital expenditures. Our fourth quarter 2006 capital expenditures were approximately $105.3 million. After giving effect to this offering at an assumed public offering price of $17.00 per share and the application of the net proceeds we will receive in this offering, we expect to have borrowings of approximately $129.9 million outstanding under our credit facility.

The credit facility matures on April 12, 2011, and borrowings under our credit facility bear interest, payable quarterly, at (a) a rate per annum equal to the London Interbank Offered Rate for one, two, three or six months as offered by the lead bank plus an applicable margin ranging from 100 to 175 basis points, depending on the percentage of our borrowing base utilized or (b) the lead bank s reference rate. The credit facility has a note amount of $750.0 million, a borrowing base of $600.0 million, subject to semi-annual redetermination, and a commitment level of $300.0 million. Our next semi-annual redetermination is during October 2007. The terms of the credit facility allow us to determine the commitment level at any level up to the borrowing base.

The credit facility contains restrictive covenants that may limit our ability to, among other things, incur additional indebtedness, sell assets, make loans to others, make investments, enter into mergers, change material contracts, incur liens and engage in certain other transactions without the prior consent of the lenders. The facility also requires us to maintain certain ratios as defined and further described in our credit facility: a Current Ratio of not less than 1.0 to 1.0 (adjusted for available borrowing capacity), a Total Funded Debt to EBITDAX, as defined, of no greater than 3.75 to 1.0. As of December 31, 2006, we were in compliance with all covenants.

Capital Expenditures and Commitments

We evaluate opportunities to purchase or sell oil and natural gas properties in the marketplace and could participate as a buyer or seller of properties at various times. We seek acquisitions that utilize our technical expertise or offer opportunities to expand our existing core areas.

We invested approximately $326.6 million for capital and exploration expenditures in 2006 as follows (in millions):

	Amount

Exploration and development drilling	$ 248.6
Purchase of properties	6.6
Dry holes	13.3
Capital facilities, workovers and recompletions	21.1
Land costs	26.1
Seismic	3.9
Vehicles, computers and other equipment	7.0
	$ 326.6

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Expenditures for exploration and development of oil and natural gas properties are the primary use of our capital resources. We anticipate investing approximately $437.0 million for capital and exploration expenditures in 2007 as follows (in millions):

	Amount
Exploration and development drilling	$ 363
Capital facilities, workovers and recompletions	31
Land costs	32
Seismic	7
Vehicles, computers & other equipment	4
	$ 437

Our budgeted capital expenditures are expected to increase approximately 34% over the $326.6 million invested during 2006. We plan to invest approximately $209 million in development drilling. In the Red River units, we plan to invest approximately $154 million to drill infill wells and extend horizontal laterals on existing wells to increase production and sweep efficiency of the enhanced recovery projects. Most of the remaining development drilling budget is expected to be invested in the drilling of development wells in the Montana Bakken field. We have budgeted approximately $173 million for exploratory drilling with approximately $71 million and $82 million allocated to drilling exploratory wells in the North Dakota Bakken field and the Woodford Shale project, respectively.

Although we cannot provide any assurance, assuming successful implementation of our strategy, including the future development of our proved reserves and realization of our cash flows as anticipated, we believe that our remaining cash balance, cash flows from operations and borrowings available under our credit facility will be sufficient to satisfy our 2007 capital budget. The actual amount and timing of our capital expenditures may differ materially from our estimates as a result of, among other things, actual drilling results, the availability of drilling rigs and other services and equipment, and regulatory, technological and competitive developments.

Shareholder Distribution

In 2004, we made a distribution of $14.9 million to our shareholders and in 2005 we made a $2.0 million distribution to our shareholders. During 2006, we declared cash dividends totaling $87.6 million to existing shareholders and, subject to forfeiture, to holders of unvested restricted stock. Of this amount, $298,000 was charged to compensation expense related to the restricted stock liability. During 2006, we paid cash dividends of $87.4 million. The unpaid balance of $218,000 relates to dividends associated with unvested restricted stock and will be paid as the restricted stock vests. On January 10, 2007, we declared a cash dividend of approximately $18.8 million to our shareholders and, subject to forfeiture, to holders of unvested restricted stock. On January 31, 2007, we paid $18.7 million of the dividend declared, of which $16.9 million was paid to our principal shareholder. On March 6, 2007, we declared a cash dividend of approximately $33.3 million to our shareholders of record and, subject to forfeiture, to holders of unvested restricted stock. On April 12, 2007, we paid $33.1 million of the dividend declared, of which $30.0 was paid to our principal shareholder. In connection with the completion of this offering, we will convert from a subchapter S-corporation to a subchapter C-corporation, and we do not anticipate paying any additional cash dividends on our common stock in the foreseeable future. See Recent Events.

Expenses to be Recognized Following Completion of the Offering

We expect to recognize a charge to earnings (estimated to be approximately $178.8 million if the conversion had occurred on December 31, 2006) to record deferred taxes as a result of our conversion to a C-corporation upon completion of this offering. This charge represents taxes provided on the difference between the book and tax basis of our assets. In addition, we expect to recognize a non-cash charge to earnings (estimated to be approximately $17.4 million as of December 31, 2006) for compensation expense associated with our equity

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compensation plans upon completion of this offering, assuming an offering price at the midpoint of the range set forth on the cover page of the prospectus.

The terms of our restricted stock grants and stock option grants under our equity compensation plans stipulate that while we are a private company, we are required to purchase the vested restricted stock and stock acquired upon stock option exercises at the request of participants in our equity compensation plans based upon the purchase price as determined by a formula specified in each award agreement. Additionally, we have the right to purchase vested shares of restricted stock and shares issued upon stock option exercises from plan participants at the same price upon termination of the participant s employment with us for any reason for a period of two years after the termination date. We have historically measured compensation cost for the awards based upon the formula purchase price which is determined by calculating a per share value for shareholders equity adjusted for the excess of each period s ending PV-10 oil and gas reserve valuation over the book value of oil and gas properties.

The right and requirement to purchase vested shares of our restricted stock and shares issued upon the exercise of stock options will lapse when we become a reporting company under Section 12 of the Exchange Act. Upon becoming a reporting company under Section 12 of the Exchange Act, we will record the charge to earnings described above to adjust the plan determined share price to the price received in this offering and account for the grants under the fair value provisions of SFAS 123(R) thereafter.

Hedging

We account for derivative instruments in accordance with SFAS No. 133 Accounting for Derivative Instruments and Hedging Activities. The specific accounting treatment for changes in the market value of the derivative instruments used in hedging activities is determined based on the designation of the derivative instruments as a cash flow or fair value hedge and effectiveness of the derivative instruments.

In 2004, we utilized fixed-price contracts and zero-cost collars to reduce exposure to unfavorable changes in oil and natural gas prices that are subject to significant and often volatile fluctuation. Under the fixed price physical delivery contracts we received the fixed price stated in the contract. Under the zero-cost collars, if the market price of crude oil was less than the ceiling strike price and greater than the floor strike price, we received market price. If the market price of crude oil exceeded the ceiling strike price or fell below the floor strike price, we received the applicable collar strike price. We recognized hedging losses of $6.4 million during 2004.

We did not hedge any of our oil or natural gas production during 2005 and 2006 and have not entered into any such hedges from January 1, 2007 through the date of this filing. We do not currently have plans to hedge any of our 2007 production.

Obligations and Commitments

We have the following contractual obligations and commitments as of December 31, 2006:

	Payments due by period				
	Total	Less than 1 year	1 - 3 years	3 - 5 years	More than 5 years
	(in thousands)				
Bank credit facility(1)	$ 140,000	$	$	$ 140,000	$
Operating lease obligations(2)	11,067	5,296	5,754	17	
Asset retirement obligations(3)	41,273	2,528	7,377	1,232	30,136
Total contractual cash obligations	$ 192,340	$ 7,824	$ 13,131	$ 141,249	$ 30,136

(1) Payments on the bank credit facility listed in the table exclude interest.

(2) Operating leases consist of compressors utilized in field operations, vehicles and office equipment.

(3) Amounts represent expected asset retirements by period.

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Critical Accounting Policies and Practices

Our historical consolidated financial statements and notes to our historical consolidated financial statements contain information that is pertinent to our management s discussion and analysis of financial condition and results of operations. Preparation of financial statements in conformity with accounting principles generally accepted in the United States requires that our management make estimates, judgments and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and the disclosure of contingent assets and liabilities. However, the accounting principles used by us generally do not change our reported cash flows or liquidity. Interpretation of the existing rules must be done and judgments made on how the specifics of a given rule apply to us.

In management s opinion, the more significant reporting areas impacted by management s judgments and estimates are revenue recognition, the choice of accounting method for oil and natural gas activities, oil and natural gas reserve estimation, asset retirement obligations and impairment of assets. Management s judgments and estimates in these areas are based on information available from both internal and external sources, including engineers, geologists and historical experience in similar matters. Actual results could differ from the estimates, as additional information becomes known.

Revenue Recognition

We derive substantially all of our revenues from the sale of oil and natural gas. Oil and gas revenues are recorded in the month the product is delivered to the purchaser and title transfers. We generally receive payment from one to three months after the sale has occurred. Each month we estimate the volumes sold and the price at which they were sold to record revenue. Variances between estimated revenue and actual amounts are recorded in the month payment is received.

Successful Efforts Method of Accounting

We utilize the successful efforts method of accounting for our oil and natural gas exploration and development activities. Exploration expenses, including geological and geophysical costs, rentals and exploratory dry holes, are charged against income as incurred. Costs of successful wells and related production equipment and developmental dry holes are capitalized and amortized on an individual property, field or unit basis using the unit-of-production method as oil and natural gas is produced. This accounting method may yield significantly different results than the full cost method of accounting.

Depreciation, depletion and amortization, or DD&A, of capitalized drilling and development costs of oil and natural gas properties are generally computed using the unit of production method on an individual property, field or unit basis based on total estimated proved developed oil and natural gas reserves. Amortization of producing leasehold is based on the unit-of-production method using total estimated proved reserves. In arriving at rates under the unit-of-production method, the quantities of recoverable oil and natural gas are established based on estimates made by our geologists and engineers and independent engineers. Service properties, equipment and other assets are depreciated using the straight-line method over estimated useful lives of 5 to 40 years. Upon sale or retirement of depreciable or depletable property, the cost and related accumulated DD&A are eliminated from the accounts and the resulting gain or loss is recognized.

Non-producing properties consist of undeveloped leasehold costs and costs associated with the purchase of certain proved undeveloped reserves. Undeveloped leasehold cost is expensed over the life of the lease or transferred to the associated producing properties. Individually significant non-producing properties are periodically assessed for impairment of value.

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Oil and Natural Gas Reserves and Standardized Measure of Future Cash Flows

Our independent engineers and technical staff prepare the estimates of our oil and natural gas reserves and associated future net cash flows. Current accounting guidance allows only proved oil and natural gas reserves to be included in our financial statement disclosures. The SEC has defined proved reserves as the estimated quantities of crude oil and natural gas which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Even though our independent engineers and technical staff are knowledgeable and follow authoritative guidelines for estimating reserves, they must make a number of subjective assumptions based on professional judgments in developing the reserve estimates. Reserve estimates are updated at least annually and consider recent production levels and other technical information about each field. Periodic revisions to the estimated reserves and future cash flows may be necessary as a result of a number of factors, including reservoir performance, new drilling, oil and natural gas prices, cost changes, technological advances, new geological or geophysical data, or other economic factors. We cannot predict the amounts or timing of future reserve revisions. If such revisions are significant, they could significantly alter future DD&A and result in impairment of assets that may be material.

Asset Retirement Obligations

In June 2001, the FASB issued SFAS No. 143, which applies to legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and the normal operation of a long-lived asset. The primary impact of this standard on us relates to oil and natural gas wells on which we have a legal obligation to plug and abandon. SFAS No. 143 requires us to record the fair value of a liability for an asset retirement obligation in the period in which it is incurred and a corresponding increase in the carrying amount of the related long-lived asset. The determination of the fair value of the liability requires us to make numerous judgments and estimates, including judgments and estimates related to the future salvage value of well equipment, future costs to plug and abandon wells, future inflation rates and estimated lives of the related assets.

Impairment of Assets

All of our long-lived assets are monitored for potential impairment when circumstances indicate that the carrying value of an asset may be greater than its future net cash flows, including cash flows from risk adjusted proved reserves. The evaluations involve a significant amount of judgment since the results are based on estimated future events, such as future sales prices for oil and natural gas, future costs to produce these products, estimates of future oil and natural gas reserves to be recovered and the timing thereof, the economic and regulatory climates and other factors. The need to test a field for impairment may result from significant declines in sales prices or downward revisions to oil and natural gas reserves. Any assets held for sale are reviewed for impairment when we approve the plan to sell. Estimates of anticipated sales prices are highly judgmental and subject to material revision in future periods. Because of the uncertainty inherent in these factors, we cannot predict when or if future impairment charges will be recorded.

Off-Balance Sheet Arrangements

Currently, we do not have any off-balance sheet arrangements.

Recent Accounting Pronouncements

On December 16, 2004, the Financial Accounting Standards Board (FASB) issued SFAS No. 123(R), Share-Based Payment , which is a revision of SFAS No. 123, Accounting for Stock-Based Compensation.

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SFAS No. 123(R) supersedes APB 25 and amends SFAS No. 95, Statement of Cash Flows. Generally, the approach in SFAS No. 123(R) is similar to the approach described in SFAS No. 123. However, SFAS No. 123(R) requires all share-based payments to employees, including grants of employee stock options, be recognized in the consolidated financial statements based on their estimated fair values. Pro forma disclosures are no longer an alternative.

We adopted SFAS 123(R) effective January 1, 2006. So long as we are not a reporting company under Section 12 of the Exchange Act, we have an obligation, and accrue a liability for the amount required, to purchase shares acquired through the exercise of stock options and vested restricted shares at a formula price set forth in the award agreements. As a result of this offering, we will no longer have this purchase obligation, and our equity compensation expense will be based on the valuation methodologies contained in SFAS 123(R).

In June 2006, the FASB issued Interpretation No. 48, *Accounting for Uncertainty in Income Taxes* (FIN 48). The interpretation clarifies the accounting for uncertainty in income taxes recognized in a company s financial statements in accordance with Statement of Financial Accounting Standards No. 109, *Accounting for Income Taxes*. The interpretation is effective for fiscal years beginning after December 15, 2006. The adoption of FIN 48 is not expected to have a material impact on our consolidated financial position or results of operations.

In September 2006, the Securities and Exchange Commission issued Staff Accounting Bulletin (SAB) No. 108, *Considering the Effects of Prior Year Misstatements when Quantifying Current Year Misstatements*. SAB No. 108 requires analysis of misstatements using both an income statement (rollover) approach and a balance sheet (iron curtain) approach in assessing materiality and provides for a one-time cumulative effect transition adjustment. We have applied the guidance of SAB No. 108 as of December 31, 2006. The application of this SAB had no effect on the consolidated financial statements.

In September 2006, the FASB finalized SFAS No. 157, *Fair Value Measurements* which will become effective in 2008. This Statement defines fair value, establishes a framework for measuring fair value, and expands disclosures about fair value measurements; however, it does not require any new fair value measurements. The provisions of SFAS No. 157 will be applied prospectively to fair value measurements and disclosures in our Consolidated Financial Statements beginning in the first quarter of 2008. The adoption of SFAS No. 157 is not expected to have a material impact on our consolidated financial position or results of operations.

In February 2007, the FASB issued SFAS No. 159, The Fair Value Option for Financial Assets and Financial Liabilities Including an amendment of FASB Statement No. 115 . This Statement provides entities with an option to choose to measure eligible items at fair value at specified election dates. If elected, an entity must report unrealized gains and losses on the item in earnings at each subsequent reporting date. The fair value option: may be applied instrument by instrument, with a few exceptions, such as investments otherwise accounted for by the equity method; is irrevocable (unless a new election date occurs); and is applied only to entire instruments and not to portions of instruments. SFAS No. 159 is effective for fiscal years beginning after November 15, 2007. Management does not believe that the implementation of SFAS No. 159 will have a material impact on our financial statements.

Inflation

Historically, general inflationary trends have not had a material effect on our operating results. However, we have experienced inflationary pressure on technical staff compensation and the cost of oilfield services and equipment due to the increase in drilling activity and competitive pressures resulting from higher oil and natural gas prices in recent years.

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Quantitative and Qualitative Disclosures About Market Risk

We are exposed to a variety of market risks including credit risk, commodity price risk and interest rate risk. We address these risks through a program of risk management which may include the use of derivative instruments.

Credit Risk. We monitor our risk of loss due to non-performance by counterparties of their contractual obligations. Our principal exposure to credit risk is through the sale of our oil and natural gas production, which we market to energy marketing companies, refineries and affiliates, as described under Certain relationships and related party transactions. We monitor our exposure to these counterparties primarily by reviewing credit ratings, financial statements and payment history. We extend credit terms based on our evaluation of each counterparty s credit worthiness. Although we have not generally required our counterparties to provide collateral to support trade receivables owed to us, we routinely require prepayment of working interest holders proportionate share of drilling costs. For such prepayments, a liability is recorded and subsequently reduced as the associated work is performed. In this manner, we reduce credit risk.

Commodity Price Risk. We are exposed to market risk as the prices of crude oil and natural gas are subject to fluctuations resulting from changes in supply and demand. To partially reduce price risk caused by these market fluctuations, we have hedged in the past, and may hedge in the future, through the utilization of derivatives, including zero-cost collars and fixed price contracts, a portion of our production. We had no hedging contracts in place during 2005 and 2006 and do not currently plan to hedge any of our 2007 production. See the commodity price sensitivity analysis included in Management s Discussion and Analysis of Financial Condition Oil and Natural Gas Prices Realized .

Interest Rate Risk. Our exposure to changes in interest rates relates primarily to long-term debt obligations. We manage our interest rate exposure by limiting our variable-rate debt to a certain percentage of total capitalization and by monitoring the effects of market changes in interest rates. We may utilize interest rate derivatives to alter interest rate exposure in an attempt to reduce interest rate expense related to existing debt issues. Interest rate derivatives are used solely to modify interest rate exposure and not to modify the overall leverage of the debt portfolio. We are exposed to changes in interest rates as a result of our credit facility. We had total indebtedness of $269.5 million outstanding under our credit facility at April 12, 2007. The impact of a 1% increase in interest rates on this amount of debt would result in increased interest expense of approximately $2.7 million and a corresponding decrease in net income. The fair value of long-term debt is estimated based on quoted market prices and management s estimate of current rates available for similar issues. The following table itemizes our long-term debt maturities and the weighted-average interest rates by maturity date:

	2006	2007	2008	2009	2010	2011	Total
				(in thousands)			
Variable rate debt:							
Credit facility:							
Principal amount	$	$	$	$	$	$ 269,500	$ 269,500
Weighted-average interest rate						6.71%	6.71%

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Business and Properties

Our Business

We are an independent oil and natural gas exploration and production company with operations in the Rocky Mountain, Mid-Continent and Gulf Coast regions of the United States. We focus our exploration activities in large new or developing plays that provide us the opportunity to acquire undeveloped acreage positions for future drilling operations. We have been successful in targeting large repeatable resource plays where horizontal drilling, advanced fracture stimulation and enhanced recovery technologies provide the means to economically develop and produce oil and natural gas reserves from unconventional formations. As a result of these efforts, we have grown substantially through the drillbit, adding 96.2 MMBoe of proved oil and natural gas reserves through extensions and discoveries from January 1, 2001 through December 31, 2006 compared to 5.1 MMBoe added through proved reserve purchases during that same period.

As of December 31, 2006, our estimated proved reserves were 118.3 MMBoe, with estimated proved developed reserves of 87.1 MMBoe, or 74% of our total estimated proved reserves. Crude oil comprised 83% of our total estimated proved reserves. At December 31, 2006, we had 1,772 scheduled drilling locations on the 1,775,000 gross (1,071,000 net) acres that we held. For the year ended December 31, 2006, we generated revenues of $483.7 million, and operating cash flows of $417.0 million.

The following table summarizes our total estimated proved reserves, PV-10 and net producing wells as of December 31, 2006, average daily production for the three months ended December 31, 2006 and the reserve-to-production ratio in our principal regions. Our reserve estimates as of December 31, 2006 are based primarily on a reserve report prepared by Ryder Scott Company, L.P., our independent reserve engineers. In preparing its report, Ryder Scott Company, L.P. evaluated properties representing approximately 83% of our PV-10. Our technical staff evaluated properties representing the remaining 17% of our PV-10.

	At December 31, 2006				Average daily production		
	Proved reserves (MBoe)	Percent of total	PV-10(1) (in millions)	Net producing wells	fourth quarter 2006 (Boe per day)	Percent of total	Annualized reserve/ production index(2)
Rocky Mountain:							
Red River units	66,527	56%	$ 791	201	11,732	44%	15.5
Bakken field	25,623	22%	441	66	7,905	30%	8.9
Other	9,077	8%	104	233	1,717	7%	14.5
Mid-Continent	16,894	14%	244	672	4,280	16%	10.8
Gulf Coast	228		4	19	869	3%	0.7
Total	118,349	100%	$ 1,584	1,191	26,503	100%	12.2

(1) PV-10 is a non GAAP financial measure and generally differs from Standardized Measure, the most directly comparable GAAP financial measure, because it does not include the effects of income taxes on future net revenues. However, our PV-10 and our Standardized Measure are equivalent because we are a subchapter S-corporation. In connection with the closing of this offering, we will convert to a subchapter C-corporation. Our pro-forma Standardized Measure, assuming our conversion to a subchapter C-corporation, was $1.0 billion at December 31, 2006. Neither PV-10 nor Standardized Measure represents an estimate of the fair market value of our oil and gas properties. We and others in the industry use PV-10 as a measure to compare the relative size and value of proved reserves held by companies without regard to the specific tax characteristics of such entities.

(2) The Annualized Reserve/Production Index is the number of years proved reserves would last assuming current production continued at the same rate. This index is calculated by dividing annualized fourth quarter 2006 production into the proved reserve quantity at December 31, 2006.

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The following table provides additional information regarding our key development areas:

	At December 31, 2006					2007 Budget	
	Developed acres		Undeveloped acres		Scheduled drilling locations(1)	Wells planned for drilling	Capital expenditures (in millions)
	Gross	Net	Gross	Net			
Rocky Mountain:							
Red River units	144,309	128,484			133	51	$ 151
Bakken field	81,761	60,176	581,846	342,321	804	58	145
Other	49,010	38,534	375,185	213,516	66	12	13
Mid-Continent	147,681	94,214	335,982	175,780	762	151	122
Gulf Coast	41,450	11,869	17,368	6,360	7	3	6
Total	464,211	333,277	1,310,381	737,977	1,772	275	$ 437

(1) Scheduled drilling locations represent total gross locations specifically identified and scheduled by management as an estimate of our future multi-year drilling activities on existing acreage. Of the total locations shown in the table, 249 are classified as PUDs. As of April 12, 2007, we have commenced drilling 116 locations shown in the table, including 67 PUD locations. Our actual drilling activities may change depending on oil and natural gas prices, the availability of capital, costs, drilling results, regulatory approvals and other factors. See Risk Factors Risks Relating to the Oil and Natural Gas Industry and Our Business.

Our Business Strategy

Our goal is to increase shareholder value by finding and developing crude oil and natural gas reserves at costs that provide an attractive rate of return on our investment. The principal elements of our business strategy are:

Growth Through Low-Cost Drilling. Substantially all of our annual capital expenditures are invested in drilling projects and acreage and seismic acquisitions. From January 1, 2001 through December 31, 2006, proved oil and natural gas reserve additions through extensions and discoveries were 96.2 MMBoe compared to 5.1 MMBoe of proved reserve purchases.

Internally Generate Prospects. Our technical staff has internally generated substantially all of the opportunities for the investment of our capital. Because we have been an early entrant in new or emerging plays, our costs to acquire undeveloped acreage have generally been less than those of later entrants into a developing play. As an example of the cost advantage of entering a play early, our per acre costs for our lease acquisitions in the North Dakota Bakken field during 2003 and 2004 were approximately 80% lower than the per acre costs paid by third parties and by us in the federal and state lease auctions for acreage near our holdings in that area during 2005.

Focus on Unconventional Oil and Natural Gas Resource Plays. Our experience with horizontal drilling, advanced fracture stimulation and enhanced recovery technologies allows us to commercially develop unconventional oil and natural gas resource plays, such as the Red River B dolomite, Bakken Shale and Woodford Shale formations. Production rates in the Red River units also have been increased through the use of enhanced recovery technology. Our production from the Red River units and the Bakken field comprised approximately 74% of our total oil and natural gas production during the three months ended December 31, 2006.

Acquire Significant Acreage Positions in New or Developing Plays. In addition to the 402,000 net acres held in the Montana and North Dakota Bakken field, we held 162,000 net acres in other oil and natural gas shale plays as of December 31, 2006. Our technical staff is focused on identifying and testing new unconventional oil and natural gas resource plays where significant reserves could be developed if commercial production rates can be achieved through advanced drilling, fracture stimulation and enhanced recovery techniques.

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Our Business Strengths

We have a number of strengths that we believe will help us successfully execute our strategies:

Large Drilling and Acreage Inventory. Within the Bakken field, we owned approximately 342,000 net undeveloped acres and had identified over 800 drilling locations as of December 31, 2006. We plan to allocate approximately 38% of our current year capital expenditure budget towards developing our Bakken acreage position. Our large number of identified drilling locations provide for a multi-year drilling inventory.

Within other unconventional plays such as the Lewis Shale in Wyoming, the Woodford Shale in Oklahoma, the New Albany Shale in Kentucky and Indiana and the Marfa Basin in Texas, we owned approximately 162,000 net undeveloped acres as of December 31, 2006.

Additionally, at December 31, 2006, we owned approximately 330,000 net undeveloped acres in other projects, including 35,000 net undeveloped acres in Roosevelt County, Montana on which we are planning a 38-square mile 3-D seismic shoot in 2007, 27,000 net undeveloped acres in the Big Horn Basin in Wyoming, on which we plan to drill 4 wells in 2007, and 24,000 net undeveloped acres in Bowman County, North Dakota, on which we plan to drill 3 horizontal Red River B wells in 2007.

Within the Red River units, we plan to drill 127 horizontal wells and 36 horizontal extensions of existing wellbores over the next two to three years in order to increase the density of both producing and injection wellbores. We believe these operations will increase production and sweep efficiency. Production in the Red River units, as projected by our proved reserve report for the year ended December 31, 2006, is expected to peak in late 2008 at approximately 19,000 net Boe per day. During the three months ended December 31, 2006, production in the Red River units averaged approximately 11,732 net Boe per day.

Horizontal Drilling and Enhanced Recovery Experience. In 1992, we drilled our initial horizontal well, and we have drilled over 350 horizontal wells since that time, which represented more than one-half of our total wells drilled during that period. We also have substantial experience with enhanced recovery methods and currently serve as the operator of 48 waterflood units. Additionally, we operate eight high pressure air injection floods in the United States.

Control Operations Over a Substantial Portion of Our Assets and Investments. As of December 31, 2006, we operated properties comprising 95% of our PV-10. By controlling operations, we are able to more effectively manage the cost and timing of exploration and development of our properties, including the drilling and fracture stimulation methods used.

Experienced Management Team. Our senior management team has extensive expertise in the oil and gas industry. Our Chief Executive Officer, Harold G. Hamm, began his career in the oil and gas industry in 1967. Our seven senior officers have an average of 26 years of oil and gas industry experience. Additionally, our technical staff, which includes 19 petroleum engineers, 12 geoscientists and seven landmen, has an average of more than 19 years experience in the industry.

Strong Financial Position. As of April 12, 2007, we had outstanding borrowings under our credit facility of approximately $269.5 million. We believe that our planned exploration and development activities will be funded substantially from our operating cash flows. After giving effect to this offering at an assumed public offering price of $17.00 per share and the application of the net proceeds we will receive in this offering, we expect to have borrowings of approximately $129.9 million outstanding under our credit facility. As a result of our limited borrowings under our credit facility and strong operational cash flows, we did not enter into any oil or natural gas price hedges for our 2006 production, and we do not currently have plans to hedge any of our 2007 production.

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Conversion to Subchapter C-Corporation

We are currently a subchapter S-corporation under the rules and regulations of the Internal Revenue Service. However, upon the consummation of this offering, we will have more shareholders than the IRS rules and regulations governing S-corporations allow, and therefore, we will convert automatically from a subchapter S-corporation to a subchapter C-corporation. In connection with this conversion, we will record a charge to earnings (estimated to be approximately $178.8 million if the conversion had occurred on December 31, 2006) to recognize deferred taxes.

Proved Reserves

The following table sets forth our estimated proved oil and natural gas reserves, the PV-10 and standardized measure of discounted future net cash flows as of December 31, 2006 by reserve category. Ryder Scott Company, L.P., our independent petroleum engineers, evaluated properties representing approximately 83% of our PV-10, and our technical staff evaluated the remaining properties. Oil and natural gas prices in effect at December 31, 2006, $61.05 per Bbl and $6.30 per MMBtu adjusted for location and quality by field, were used in the computation of future net cash flows.

	Oil (MBbls)	Gas (MMcf)	Total (MBoe)	PV-10(1) (in millions)
Proved developed producing	71,951	69,896	83,600	$ 1,262
Proved developed non-producing	3,385	524	3,472	19
Proved undeveloped	22,702	51,445	31,277	303
Total proved	98,038	121,865	118,349	$ 1,584
Standardized Measure(2)				$ 1,584
Pro Forma Standardized Measure(2)				$ 1,027

(1) PV-10 is a non GAAP financial measure and generally differs from Standardized Measure, the most directly comparable GAAP financial measure, because it does not include the effects of income taxes on future net revenues. However, our PV-10 and our Standardized Measure are equivalent because we are a subchapter S-corporation. In connection with the closing of this offering, we will convert to a subchapter C-corporation. Our pro-forma Standardized Measure, assuming our conversion to a subchapter C-corporation, was $1.0 billion at December 31, 2006. Neither PV-10 nor Standardized Measure represents an estimate of the fair market value of our oil and gas properties. We and others in the industry use PV-10 as a measure to compare the relative size and value of proved reserves held by companies without regard to the specific tax characteristics of such entities.

(2) As of December 31, 2006, Continental Resources was structured as a subchapter S-corporation. Accordingly, no provision for federal or state corporate income taxes has been provided because taxable income is passed through to our shareholders. Pro Forma Standardized Measure assumes Continental Resources was restructured as a subchapter C-corporation as of December 31, 2006.

The following table sets forth our estimated proved reserves, percent of total proved reserves that are proved developed and PV-10 as of December 31, 2006 by region:

	Oil (MBbls)	Gas (MMcf)	Total (MBoe)	% Proved developed	PV-10(1) (in millions)
Rocky Mountain:					
Red River units	60,697	34,980	66,527	75%	$ 791
Bakken field	23,132	14,946	25,623	64%	441
Other	8,039	6,226	9,077	65%	104
Mid-Continent	6,127	64,605	16,894	85%	244
Gulf Coast	43	1,108	228	100%	4
Total	98,038	121,865	118,349	74%	$ 1,584

(1) PV-10 is a non GAAP financial measure and generally differs from Standardized Measure, the most directly comparable GAAP financial measure, because it does not include the effects of income taxes on future net revenues. However, our PV-10 and our Standardized Measure are equivalent because we are a subchapter S-corporation. In connection with the closing of this offering, we will convert to a subchapter C-corporation. Our pro-forma Standardized Measure, assuming our conversion to a subchapter C-corporation, was $1.0 billion at December 31, 2006. Neither PV-10 nor Standardized Measure represents an estimate of the fair market value of our oil and gas properties. We and others in the industry use PV-10 as a measure to compare the relative size and value of proved reserves held by companies without regard to the specific tax characteristics of such entities.

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Production and Price History

The following table sets forth summary information concerning our production results, average sales prices and production costs for the years ended December 31, 2004, 2005 and 2006:

	Year ended December 31,		
	2004	2005	2006
Net production volumes:			
Oil (MBbls)(1)	3,688	5,708	7,480
Natural gas (MMcf)	8,794	9,006	9,225
Oil equivalents (MBoe)	5,154	7,209	9,018
Average prices(1):			
Oil, without hedges ($/Bbl)	$ 38.85	$ 52.45	$ 55.30
Oil, with hedges ($/Bbl)	37.12	52.45	55.30
Natural gas ($/Mcf)	5.06	6.93	6.08
Oil equivalents, without hedges ($/Boe)	36.45	50.19	52.09
Oil equivalents, with hedges ($/Boe)	35.20	50.19	52.09
Costs and expenses(1):			
Production expense ($/Boe)	$ 8.49	$ 7.32	$ 6.99
Production tax ($/Boe)	2.39	2.22	2.48
General and administrative ($/Boe)	2.41	4.34	2.56
DD&A expense ($/Boe)(2)	7.02	6.50	6.91

(1) Oil sales volumes are 21 MBbls less than oil production volumes for the year ended December 31, 2006. Average prices and per unit costs have been calculated using sales volumes.

(2) Rate is determined based on DD&A expense derived from oil and natural gas assets.

The following table sets forth information regarding our average daily production during the fourth quarter of 2006:

	Average daily production fourth quarter 2006		
	Bbls	Mcf	Boe
Rocky Mountain			
Red River units	11,661	428	11,732
Bakken field	7,154	4,506	7,905
Other	1,277	2,638	1,717
Mid-Continent	1,717	15,377	4,280
Gulf Coast	219	3,898	869

Total	22,028	26,847	26,503

Productive Wells

The following table presents the total gross and net productive wells by region and by oil or gas completion as of December 31, 2006:

	Oil wells		Natural gas wells		Total wells	
	Gross	Net	Gross	Net	Gross	Net
Rocky Mountain:						
Red River units	220	201			220	201
Bakken field	116	66			116	66
Other	259	232	3	1	262	233
Mid-Continent	703	546	253	126	956	672
Gulf Coast	7	4	28	15	35	19
Total	1,305	1,049	284	142	1,589	1,191

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Gross wells are the number of wells in which a working interest is owned and net wells are the total of our fractional working interests owned in gross wells. As of December 31, 2006, we owned interests in no wells containing multiple completions.

Developed and Undeveloped Acreage

The following table presents the total gross and net developed and undeveloped acreage by region as of December 31, 2006:

	Developed acres		Undeveloped acres		Total acres	
	Gross	Net	Gross	Net	Gross	Net
Rocky Mountain:						
Red River units	144,309	128,484			144,309	128,484
Bakken field	81,761	60,176	581,846	342,321	663,607	402,497
Other	49,010	38,534	375,185	213,516	424,195	252,050
Mid-Continent	147,681	94,214	335,982	175,780	483,663	269,994
Gulf Coast	41,450	11,869	17,368	6,360	58,818	18,229
Total	464,211	333,277	1,310,381	737,977	1,774,592	1,071,254

The following table sets forth the number of gross and net undeveloped acres as of December 31, 2006 that will expire over the next three years by region unless production is established within the spacing units covering the acreage prior to the expiration dates:

	2007		2008		2009	
	Gross	Net	Gross	Net	Gross	Net
Rocky Mountain:						
Red River units						
Bakken field	99,135	58,471	185,639	100,167	224,382	130,912
Other	82,483	52,036	87,567	44,979	37,997	17,188
Mid-Continent	40,909	22,355	64,527	26,977	66,132	28,250
Gulf Coast	1,788	1,226	9,959	2,046	2,617	2,049
Total	224,315	134,088	347,692	174,169	331,128	178,399

Drilling Activity

During the three years ended December 31, 2006, we drilled exploratory and development wells as set forth in the table below:

	2004		2005		2006	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Exploratory wells:						
Oil	12	5.6	13	5.9	17	8.4
Gas	5	0.9	2	1.3	25	4.9
Dry	17	10.5	11	6.9	17	9.4
Total exploratory wells	34	17.0	26	14.1	59	22.7
Development wells:						
Oil	14	8.3	50	30.6	83	57.0
Gas	13	5.7	15	7.6	34	14.5
Dry	4	2.6	3	3.0	7	4.3
Total development wells	31	16.6	68	41.2	124	75.8
Total wells	65	33.6	94	55.3	183	98.5

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As of December 31, 2006, there were 27 gross (15.6 net) development wells and 31 gross (14.2 net) exploratory wells in the process of drilling. As of April 12, 2007, 25 gross (15.0 net) wells of the development wells in process as of December 31, 2006, were completed as producers, and 2 gross (0.6 net) wells were in the process of completion. As of April 12, 2007, 15 gross (4.3 net) wells of the exploratory wells in process as of December 31, 2006 were completed as producers, 1 gross (1.0 net) well was a dry hole and the remaining exploratory wells were drilling or in the process of completion.

As of April 12, 2007, we operated 17 rigs on our properties and have plans to add additional rigs during the next six months. There can be no assurance, however, that additional rigs will be available to us at an attractive cost. See Risk Factors The unavailability or high cost of additional drilling rigs, equipment, supplies, personnel and oilfield services could adversely affect our ability to execute our exploration and development plans within our budget and on a timely basis.

Summary of Oil and Natural Gas Properties and Projects

Rocky Mountain Region

Our properties in the Rocky Mountain region represented 84% of our PV-10 as of December 31, 2006. During the three months ended December 31, 2006, our average production from such properties was 20,092 net Bbls of oil and 7,572 net Mcf of natural gas per day. Our principal producing properties in this region are in the Red River units, the Bakken field and the Big Horn Basin. Additionally, we have prospective acreage for the Lewis Shale in southern Wyoming, another unconventional resource play in the Rocky Mountain Region.

For the six month period ended October 31, 2006, we ranked second among all oil companies in terms of gross operated crude oil production within the Rocky Mountain states of Montana, North Dakota, South Dakota and Wyoming.

Red River Units

Our Red River units represented 59% of our PV-10 in the Rocky Mountain Region as of December 31, 2006 and 55% of our average daily Rocky Mountain Region equivalent production for the three months ended December 31, 2006. The eight units comprising the Red River units are located along the Cedar Hills Anticline in North Dakota, South Dakota and Montana and produce oil and natural gas from the Red River B formation, a thin, continuous, dolomite formation at depths of 8,000 to 9,500 feet. Our Red River units comprise a portion of the Cedar Hills field, listed by the Energy Information Administration in 2004 as the 23rd largest field in the United States ranked by liquids proved reserves.

Cedar Hills Units. The Cedar Hills North unit (CHNU) is located in Bowman and Slope Counties, North Dakota. We drilled the initial horizontal well in the CHNU, the Ponderosa 1-15, in April 1995. As of December 31, 2006, we had drilled 154 horizontal wells within this 49,700-acre unit, with 90 producing wellbores and the remainder serving as injection wellbores. We operate and own a 98% working interest in the CHNU.

The Cedar Hills West unit (CHWU), in Fallon County, Montana, is contiguous to the northern portion of CHNU. As of December 31, 2006, this 7,800-acre unit contained ten horizontal producing wells and four HPAI wells. We operate and own a 100% working interest in the CHWU.

In January 2003, we commenced enhanced recovery in the two Cedar Hills units, with HPAI used throughout most of the area and water injected generally along the boundary of the CHNU. Under HPAI, compressed air injected into a reservoir oxidizes residual oil and produces flue gases (primarily carbon dioxide and nitrogen) that mobilize and sweep the crude oil into producing wellbores. In response to the HPAI and water injection, production from the Cedar Hills units increased to 9,561 net Boe per day in December 2006 from 2,185 net Boe per day in November 2003. As of December 31, 2006, the average density in the Cedar Hill units was

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approximately one producing wellbore each 575 acres. We currently plan to drill 83 new horizontal wellbores and 9 horizontal extensions of existing wellbores in the Cedar Hills units during the next two to three years, increasing the density of both the producing and injection wellbores. We believe this operation will increase production and sweep efficiency. Production in the two units, as projected by our proved reserves report for the year ended December 31, 2006, is expected to peak in late 2008 at approximately 15,400 net Boe per day. In 2007, we plan to invest approximately $95 million drilling in the Cedar Hills units.

On November 8, 2005, we entered into a contract with Hiland Partners, LP (Hiland) for the processing and treatment of gas produced from the CHNU and CHWU. Under the terms of the contract we agree to deliver low pressure gas to Hiland for compression, treatment and processing at a facility to be constructed by Hiland. Nitrogen and carbon dioxide must be removed from the gas production associated with the increasing oil production from CHNU and CHWU for the gas production to be marketable. Under the terms of the contract, we pay $0.60 per Mcf in gathering and treating fees, and 50% of the electrical costs attributable to compression and plant operation and receive 50% of the proceeds from residue gas and plant product sales. After we deliver 36 Bcf of gas, the $0.60 per Mcf gathering and treating fee is eliminated. If the average composite volume of carbon dioxide is less than 10%, we pay an additional $0.10 per Mcf treating fee, otherwise the treating fee is $0.20 per Mcf. The plant is currently expected to be operational in May 2007.

Medicine Pole Hills Units. The Medicine Pole Hills units (MPHU) are approximately five miles east of the southern portion of the CHNU. We acquired the Medicine Pole Hills unit in 1995. At that time, the 9,600- acre unit consisted of 18 vertical producing wellbores and four injection wellbores under HPAI producing 525 net Bbls of oil per day. We have since drilled 33 horizontal wellbores extending production to the west with the formation of the 15,000-acre Medicine Pole Hills West unit and to the south, with the 11,500-acre Medicine Pole Hills South unit. All three units are under HPAI. We operate and own an average 77% working interest in the three units. Production from the units averaged 1,105 net Bbls of oil and 184 net Mcf of natural gas per day in December 2006. We currently plan to drill 16 new horizontal wellbores and seven horizontal extensions of existing wellbores during the next two years, increasing the density of both producing and injection wellbores. We believe these operations will increase production and sweep efficiency. In 2007, we plan to invest approximately $15 million for drilling in MPHU.

Buffalo Red River Units. The three contiguous Buffalo Red River units (Buffalo, West Buffalo and South Buffalo) are located in Harding County, South Dakota, approximately 21 miles south of the MPHU. When we purchased the units in 1995, there were 73 vertical producing wellbores and 38 injection wellbores under HPAI producing approximately 1,906 net Bbls of oil per day. We operate and own an average working interest of 95% in the 32,900 acres comprising the three units. During 2005 and 2006, we re-entered 23 existing vertical wells and drilled horizontal laterals to increase production and sweep efficiency. Production for the month of December 2006 was 1,443 net Bbls of oil per day compared to an average of 1,162 net Bbls of oil per day for the first half of 2005. We currently plan to drill 20 horizontal extensions of existing wellbores and 28 new horizontal wellbores in the Buffalo Red River units over the next three years. We believe these operations will increase production and sweep efficiency. In 2007, we plan to invest $16 million for drilling in the Buffalo Red River units.

Bakken Field

Our properties within the Bakken field in Montana and North Dakota represented 33% of our PV-10 in the Rocky Mountain Region as of December 31, 2006 and 37% of our average daily Rocky Mountain Region equivalent production for the three months ended December 31, 2006. The Bakken formation is widespread and relatively uniform in development throughout the Montana and North Dakota portions of the Williston Basin. The Bakken formation consists of three lithologic members the upper shale, middle member and locally a lower shale. The shales are highly organic, thermally mature and overpressured and act as both a source and

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reservoir for the oil. The middle member is also productive locally and varies in composition from a silty dolomite, to shalely limestone or sand across the Williston Basin. Horizontal drilling and advanced fracture stimulation technologies have enabled commercial recovery from this historically non-commercial reservoir. Generally, the Bakken formation is drilled horizontally on 1,280-acre units to vertical depths ranging from 9,000 to 10,500 feet with opposing horizontal laterals each extending approximately 4,500 feet, for a total drilled footage of approximately 18,000 to 21,000 feet. The wells are typically fracture stimulated to maximize recovery and economic returns.

Richland County, Montana. Commercial production data available on wells completed after February 2001 in the Bakken formation by various operators in Richland County, Montana report 433 productive wells with cumulative production as of October 2006 of 43 MMBbls of oil and 25 Bcf of natural gas. Daily production from these wells for the month of October 2006 was approximately 52 MBbls of oil and 36 MMcf of natural gas.

Our initial well in the Richland County, Montana portion of the Bakken field, the Goss #34-26 completed in August 2003, has produced approximately 218,000 gross Bbls of oil and 100,000 gross Mcf of natural gas as of December 31, 2006 and averaged 75 gross Bbls of oil and 52 gross Mcf of natural gas per day during the month of December 2006. Our average daily rate from 100 gross (59 net) wells in this field was approximately 6,737 net Bbls of oil and 4,372 net Mcf of natural gas during the month of December 2006. Substantially all of our wells have been horizontally drilled on 1,280-acre units within the middle dolomite member, which is well developed under our leasehold in Richland County. In 2006, we drilled several second horizontal wells in 1,280-acre units and plan to drill a horizontal well in 2007 to test the incremental reserves of a third well in a 1,280-acre unit.

As of December 31, 2006, we held 104,000 gross (79,000 net) undeveloped acres in the Richland County, Montana portion of the Bakken field with 39 proved undeveloped and 58 additional scheduled drilling locations. We currently have five operated drilling rigs in this part of the field and plan to invest $57 million in the drilling of 21 horizontal Bakken wells in Montana during 2007.

North Dakota Bakken. Encouraged by the results in Richland County, Montana, operators have begun drilling horizontal wells in the Bakken formation in North Dakota. Since this play is in the early stages of development, results are limited but encouraging. As of December 31, 2006, production data had been reported to the North Dakota Oil and Gas Commission on 86 horizontal North Dakota Bakken wells completed since March 2004. The initial production rates on the 86 wells ranged up to 1,355 Boe per day and averaged 192 Boe per day per well. Cumulative and daily production from the 86 wells as of December 31, 2006 was 2.0 MMBoe and 5,863 Boe, respectively.

As in Richland County, Montana, the upper Bakken shale in western North Dakota is highly organic, thermally mature and over-pressured. Within our North Dakota acreage, the formation is found at vertical depths ranging from 8,500 to 11,000 feet. In North Dakota, the Bakken formation gross interval ranges up to 130 feet compared to about 30 feet in Richland County, Montana. Similarly, the upper Bakken shale thickness ranges up to 20 feet in North Dakota compared to about 7 feet in Richland County, Montana. The middle dolomite member of the Bakken formation in the southern portion of our North Dakota acreage is similar to that present in the Richland County, Montana producing area. Moving north on our acreage, the middle dolomite member increases in thickness but diminishes in reservoir quality. We believe the loss of quality of the middle member is offset by the increasing thickness of the upper and lower shales as one moves north and the strategic position of our acreage along the axis of the Nesson anticline.

In March 2004, we served as contract operator on a well completed in the Bakken formation near the northern border of our acreage. We drilled a 4,376-foot single horizontal lateral within the middle dolomite member of the Bakken Shale in an abandoned dry hole. The well has produced approximately 58,000 gross Boe

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through December 31, 2006 and is estimated to ultimately produce approximately 219,000 gross Boe. The well, initially owned by our principal shareholder and his family, was acquired by us in August 2005.

In October 2004, we completed a well in the Bakken formation on the extreme southeastern edge of our North Dakota acreage in a well originally planned as a shallower Lodgepole formation test. This well is over 120 miles south of our initial test. The well was unsuccessful in the Lodgepole formation and was deepened to test the Bakken formation at this location. The middle dolomite member significantly thins along the southern edge of our acreage and, in this test well, the middle member was essentially not present. The well has produced approximately 17,000 gross Boe through December 31, 2006 from a single 6,199-foot horizontal lateral and is estimated ultimately to produce approximately 32,000 gross Boe.

In 2005, we participated with a small working interest in two non-operated Bakken formation tests in North Dakota. One is expected to ultimately produce about 12,000 gross Boe and the other, 121,000 gross Boe.

In 2006, we participated in 9 gross (4.8 net) operated and 10 gross (1.6 net) non-operated horizontal Bakken Shale wells in North Dakota. Of these, 16 gross (5.2 net) have been completed as producers and the remaining are awaiting completion. Initial production rates for the 16 producing wells ranged from 182 Boe to 1,355 Boe per day.

In June 2006, we entered into an agreement with ConocoPhillips Company to form an area of mutual interest (AMI) within Dunn, McKenzie, Mountrail and Williams Counties, North Dakota and jointly drill wells to test the Bakken formation. Within the AMI, we own approximately 97,000 net acres. Initial wells proposed under the agreement establish exploration blocks covering the 1,280-acre spacing unit for the initial well and two adjacent 1,280-acre spacing units. Each party has the right to acquire from the other party an undivided 50% interest in the exploration block acreage owned by the other party at $500 per net acre. ConocoPhillips Company has proposed and we have agreed to participate in the initial three wells to be drilled under the agreement. As of April 12, 2007, ConocoPhillips Company had three drilling rigs operating within the AMI and we had two drilling rigs operating on our North Dakota Bakken acreage outside the AMI.

As of December 31, 2006, we held 478,000 gross (263,000 net) undeveloped acres in contiguous counties in North Dakota across the state border from the Richland County, Montana drilling activity. During 2007, we plan to invest approximately $71 million in the drilling of 37 horizontal Bakken wells on our acreage in North Dakota.

Big Horn Basin and Other

Our wells within the Big Horn Basin in northern Wyoming and other areas within the Rocky Mountain region represented 8% of our PV-10 in the Rocky Mountain Region as of December 31, 2006 and 8% of our average daily Rocky Mountain Region equivalent production for the three months ended December 31, 2006. During the three months ended December 31, 2006, we produced an average of 1,277 net Bbls of oil and 2,638 net Mcf of natural gas per day from our wells in the Big Horn Basin and other areas within the Rocky Mountain region. Our principal property in the Big Horn Basin, the Worland field, produces primarily from the Phosphoria formation. We have 41 additional proved undeveloped drilling locations in the Worland field. During 2007, we plan to invest approximately $2 million in the drilling of 4 wells in this region.

Lewis Shale Project

As of December 31, 2006, we owned approximately 123,000 gross (31,000 net) undeveloped acres in the Washakie Basin in Carbon and Sweetwater Counties, Wyoming. Our objective is the Lewis Shale, a shale formation up to 1,500 feet thick with thin interbedded and discontinuous siltstones and sandstones. Underlying our acreage, the Lewis Shale is over-pressured, fractured and gas charged with the potential to develop into an economic unconventional gas resource play. Previous drilling in the area has encountered gas from the thick,

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fractured shale, but only the thin, isolated sands within the shale have been produced. As of October 2006, the Triton field, located in the center of our acreage block, has produced a total of 6.7 Bcf of natural gas from 5 wells with up to 40 feet of perforations in thin sands within the Lewis Shale. We plan to produce the entire Lewis Shale sequence with the expectation that ultimate recoveries per well will be greater than previous results.

During 2006, we participated in the drilling of 4 gross (1.3 net) productive wells in the Lewis Shale project. The first well, the CEPO Federal 20-17, was completed in September 2006, has produced approximately 600,000 Mcf of natural gas through March 2007 and produced at an average rate of approximately 4,300 Mcf of natural gas per day in March 2007. The well is producing from the first of two productive sands encountered in the well. The second sand tested at rates of 2,000 Mcf of natural gas per day with flowing pressures of 1,000 pounds per square inch and will be produced at a later date. The second well, the Neptune 13-11, began producing at a rate of approximately 1,200 Mcf of natural gas per day after fracture stimulation in August 2006. The well has produced approximately 173,000 Mcf of natural gas through March 2007 and produced at an average rate of approximately 320 Mcf of natural gas per day in March 2007. The third well, the Barricade 44-1, was completed in December 2006 and produced at an average rate of approximately 320 Mcf of natural gas per day in March 2007. The fourth well, the CEPO Lewis 23-17, is currently being completed and produced at a rate of approximately 4,450 Mcf of natural gas per day on April 12, 2007. We participated in the drilling of a fifth well in the project in 2007 which was abandoned during drilling operations due to mechanical problems. During 2007, we plan to invest approximately $1 million in the drilling of two Lewis Shale wells.

Mid-Continent Region

Our properties in the Mid-Continent Region represented 15% of our PV-10 as of December 31, 2006. During the three months ended December 31, 2006, our average production from such properties was 1,717 net Bbls of oil and 15,377 net Mcf of natural gas per day. Our principal producing properties in this region are located in the Anadarko Shelf of western Oklahoma and the Illinois Basin. We have also acquired acreage in three unconventional resource plays: the Woodford Shale, New Albany Shale and Marfa Basin.

Anadarko Shelf

Our properties within the Anadarko Basin represent 64% of our PV-10 in the Mid-Continent Region as of December 31, 2006 and 63% of our average daily Mid-Continent Region equivalent production for the three months ended December 31, 2006. Our wells within the Anadarko Basin produce from a variety of sands and carbonates in both stratigraphic and structural traps. In 2007, we plan to invest approximately $9 million in the drilling of 6 wells in the Anadarko Basin.

Illinois Basin

Our properties within the Illinois Basin represent 36% of the PV-10 in the Mid-Continent Region as of December 31, 2006 and 37% of our average daily Mid-Continent Region equivalent production for the three months ended December 31, 2006. Our wells within the Illinois Basin produce primarily crude oil from units comprised of shallow sand formations under water injection. In 2007, we plan to invest approximately $4 million in the drilling of 22 wells in the Illinois Basin.

Woodford Shale Project

We owned approximately 91,000 gross (30,000 net) undeveloped acres in Atoka, Coal, Hughes and Pittsburg Counties, Oklahoma as of December 31, 2006. We continue to add to our acreage position and owned approximately 108,000 gross (35,000 net) acres in the Woodford Shale project at March 1, 2007. Our drilling objective is the 100 to 175-foot thick Woodford Shale at vertical depths of 6,000 to 12,500 feet. We believe horizontal drilling, combined with advanced fracture stimulation technology, may provide the means for commercial development of this organic rich, gas-bearing shale. This play is in the early stages of development

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and data is limited. However, we are encouraged by recent drilling results. A total of 72 horizontal Woodford Shale completions have been reported within Atoka, Coal, Hughes and Pittsburg Counties during the past three years with reported initial production rates ranging from 125 to 8,700 Mcf of natural gas per day. The number of rigs drilling horizontal Woodford wells in these counties has increased to 38 as of April 12, 2007. During 2006, we participated in 4 gross (1.3 net) operated and 35 gross (1.8 net) non-operated horizontal Woodford Shale wells. Of these 39 wells, 30 gross (1.6 net) wells have been completed as producers, 7 gross (1.2 net) are drilled and awaiting completion and 2 gross (0.3 net) are being drilled. Initial production rates for the 30 producing wells ranged from 705 Mcf to 8,700 Mcf of natural gas per day and averaged 3,139 Mcf of natural gas per day. In July 2006, we completed a 19 square mile 3D seismic survey over portions of our acreage to identify prospective drilling locations. As of April 12, 2007, we had three operated rigs drilling horizontal Woodford Shale wells and plan to add a fourth rig in May 2007. As of April 12, 2007, we also have working interests in five non-operated wells that are in the process of drilling. We anticipate investing approximately $82 million in the drilling of 123 Woodford Shale wells in 2007.

Marfa Basin Shale Project

In April 2006, we purchased a 50% working interest in approximately 135,000 acres in the Marfa Basin, a lightly explored basin located in Presidio and Brewster Counties, Texas. The Marfa Basin is geologically similar to other gas-prone basins along the Ouachita Overthrust belt, such as the Fort Worth and Arkoma Basins, and is located adjacent to the Delaware Basin where exploration for gas from Barnett equivalent shales is underway by several companies in Culberson County. We are targeting a highly organic and thermally mature sequence of shales up to 600 feet thick that contains Woodford and Barnett equivalent shales. There are no wells producing gas from these shales in the basin. In 2006, we re-entered an existing cased wellbore and tested the productivity of the shales. The well produced natural gas, but at a noncommercial rate. We have not yet determined our 2007 plans for this project.

New Albany Shale Project

We owned approximately 42,000 gross (34,000 net) undeveloped acres in Kentucky and Indiana as of December 31, 2006. Our drilling objective is the New Albany Shale, an organically rich, gas-bearing Devonian age shale equivalent to the prolific Antrim Shale in Michigan. The New Albany Shale averages 100 feet thick under our acreage and is found at vertical depths of 1,500 to 4,500 feet. We believe the potential exists for the New Albany Shale to be an economic unconventional natural gas resource play. In December 2005, we completed our initial horizontal well in the New Albany Shale as an uncommercial producer. We plan to use the core and production data from this well and drilling results of other operators in the play to develop our future drilling plans.

Gulf Coast Region

During the three months ended December 31, 2006, our average production from our Gulf Coast properties was 219 net Bbls of oil and 3,898 net Mcf of natural gas per day. Our principal producing properties in this region are located in South Texas and Louisiana. In 2007, we plan to invest approximately $4 million in the drilling of 3 wells in the Texas and Louisiana Gulf Coast.

Marketing and Major Customers

We principally sell our oil and natural gas production to end users, marketers and other purchasers that have access to nearby pipeline facilities. In areas where there is no practical access to pipelines, oil is transported by truck to storage facilities. Our marketing of oil and natural gas can be affected by factors beyond our control, the

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effects of which cannot be accurately predicted. For a description of some of these factors, see Risk factors Market conditions or operational impediments may hinder our access to oil and natural gas markets or delay our production.

For the year ended December 31, 2006, oil sales to Banner and Nexen Marketing U.S.A. Inc. accounted for approximately 14% and 19%, respectively, of our total oil and natural gas sales. No other purchasers accounted for more than 10% of our total oil and gas sales. Banner was an affiliate of ours as described under Certain Relationships and Related Party Transactions. In February 2006, we decided to market the majority of our crude oil in the Rocky Mountain region directly or through a wholly owned subsidiary rather than through an affiliate, and, as Banner has existing contacts and relationships with crude oil purchasers, we decided to purchase Banner. On March 30, 2006, we acquired Banner for approximately $8.8 million, the book value of working capital, principally cash, accounts receivable, crude oil inventory and accounts payable. We believe that the loss of any of these purchasers would not have a material adverse effect on our operations, as there are a number of alternative crude oil purchasers in our producing regions.

Title to Properties

As is customary in the oil and gas industry, we initially conduct only a cursory review of the title to our properties on which we do not have proved reserves. Prior to the commencement of drilling operations on those properties, we conduct a thorough title examination and perform curative work with respect to significant defects. To the extent title opinions or other investigations reflect title defects on those properties, we are typically responsible for curing any title defects at our expense. We generally will not commence drilling operations on a property until we have cured any material title defects on such property. We have obtained title opinions on substantially all of our producing properties and believe that we have satisfactory title to our producing properties in accordance with standards generally accepted in the oil and gas industry. Prior to completing an acquisition of producing oil and natural gas leases, we perform title reviews on the most significant leases and, depending on the materiality of properties, we may obtain a title opinion or review previously obtained title opinions. Our oil and natural gas properties are subject to customary royalty and other interests, liens to secure borrowings under our credit facility, liens for current taxes and other burdens which we believe do not materially interfere with the use or affect our carrying value of the properties.

Competition

We operate in a highly competitive environment for acquiring properties, marketing oil and natural gas and securing trained personnel. Our competitors vary within the regions in which we operate, and some of our competitors may possess and employ financial, technical and personnel resources substantially greater than ours, which can be particularly important in the areas in which we operate. Those companies may be able to pay more for productive oil and natural gas properties and exploratory prospects and to evaluate, bid for and purchase a greater number of properties and prospects than our financial or personnel resources permit. In addition, shortages or the high cost of drilling rigs could delay or adversely affect our development and exploration operations. Our ability to acquire additional prospects and to find and develop reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. Also, there is substantial competition for capital available for investment in the oil and natural gas industry.

Regulation of the Oil and Natural Gas Industry

Regulation of Transportation of Oil

Sales of crude oil, condensate and natural gas liquids are not currently regulated and are made at negotiated prices. Nevertheless, Congress could reenact price controls in the future.

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Our sales of crude oil are affected by the availability, terms and cost of transportation. The transportation of oil in common carrier pipelines is also subject to rate regulation. The Federal Energy Regulatory Commission, or the FERC, regulates interstate oil pipeline transportation rates under the Interstate Commerce Act. In general, interstate oil pipeline rates must be cost-based, although settlement rates agreed to by all shippers are permitted and market-based rates may be permitted in certain circumstances. Effective January 1, 1995, the FERC implemented regulations establishing an indexing system (based on inflation) for transportation rates for oil that allowed for an increase or decrease in the cost of transporting oil to the purchaser. A review of these regulations by the FERC in 2000 was successfully challenged on appeal by an association of oil pipelines. On remand, the FERC in February 2003 increased the index slightly, effective July 2001. Intrastate oil pipeline transportation rates are subject to regulation by state regulatory commissions. The basis for intrastate oil pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate oil pipeline rates, varies from state to state. Insofar as effective interstate and intrastate rates are equally applicable to all comparable shippers, we believe that the regulation of oil transportation rates will not affect our operations in any way that is of material difference from those of our competitors.

Further, interstate and intrastate common carrier oil pipelines must provide service on a non-discriminatory basis. Under this open access standard, common carriers must offer service to all similarly situated shippers requesting service on the same terms and under the same rates. When oil pipelines operate at full capacity, access is governed by prorationing provisions set forth in the pipelines published tariffs. Accordingly, we believe that access to oil pipeline transportation services generally will be available to us to the same extent as to our competitors.

Regulation of Transportation and Sale of Natural Gas

Historically, the transportation and sale for resale of natural gas in interstate commerce have been regulated pursuant to the Natural Gas Act of 1938, the Natural Gas Policy Act of 1978 and regulations issued under those Acts by the FERC. In the past, the federal government has regulated the prices at which natural gas could be sold. While sales by producers of natural gas can currently be made at uncontrolled market prices, Congress could reenact price controls in the future. Deregulation of wellhead natural gas sales began with the enactment of the Natural Gas Policy Act. In 1989, Congress enacted the Natural Gas Wellhead Decontrol Act which removed all Natural Gas Act and Natural Gas Policy Act price and non-price controls affecting wellhead sales of natural gas effective January 1, 1993.

FERC regulates interstate natural gas transportation rates and service conditions, which affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas. Since 1985, the FERC has endeavored to make natural gas transportation more accessible to natural gas buyers and sellers on an open and non-discriminatory basis. The FERC has stated that open access policies are necessary to improve the competitive structure of the interstate natural gas pipeline industry and to create a regulatory framework that will put natural gas sellers into more direct contractual relations with natural gas buyers by, among other things, unbundling the sale of natural gas from the sale of transportation and storage services. Beginning in 1992, the FERC issued Order No. 636 and a series of related orders to implement its open access policies. As a result of the Order No. 636 program, the marketing and pricing of natural gas have been significantly altered. The interstate pipelines traditional role as wholesalers of natural gas has been eliminated and replaced by a structure under which pipelines provide transportation and storage service on an open access basis to others who buy and sell natural gas. Although the FERC s orders do not directly regulate natural gas producers, they are intended to foster increased competition within all phases of the natural gas industry.

In 2000, the FERC issued Order No. 637 and subsequent orders, which imposed a number of additional reforms designed to enhance competition in natural gas markets. Among other things, Order No. 637 effected

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changes in FERC regulations relating to scheduling procedures, capacity segmentation, penalties, rights of first refusal and information reporting. Most pipelines tariff filings to implement the requirements of Order No. 637 have been accepted by the FERC and placed into effect.

We cannot accurately predict whether the FERC s actions will achieve the goal of increasing competition in markets in which our natural gas is sold. Additional proposals and proceedings that might affect the natural gas industry are pending before the FERC and the courts. The natural gas industry historically has been very heavily regulated. Therefore, we cannot provide any assurance that the less stringent regulatory approach recently established by the FERC will continue. However, we do not believe that any action taken will affect us in a way that materially differs from the way it affects other natural gas producers.

Gathering service, which occurs upstream of jurisdictional transmission services, is regulated by the states onshore and in state waters. Although its policy is still in flux, FERC has reclassified certain jurisdictional transmission facilities as non-jurisdictional gathering facilities, which has the tendency to increase our costs of getting gas to point of sale locations.

Intrastate natural gas transportation is also subject to regulation by state regulatory agencies. The basis for intrastate regulation of natural gas transportation and the degree of regulatory oversight and scrutiny given to intrastate natural gas pipeline rates and services varies from state to state. Insofar as such regulation within a particular state will generally affect all intrastate natural gas shippers within the state on a comparable basis, we believe that the regulation of similarly situated intrastate natural gas transportation in any states in which we operate and ship natural gas on an intrastate basis will not affect our operations in any way that is of material difference from those of our competitors. Like the regulation of interstate transportation rates, the regulation of intrastate transportation rates affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas.

Regulation of Production

The production of oil and natural gas is subject to regulation under a wide range of local, state and federal statutes, rules, orders and regulations. Federal, state and local statutes and regulations require permits for drilling operations, drilling bonds and reports concerning operations. All of the states in which we own and operate properties have regulations governing conservation matters, including provisions for the unitization or pooling of oil and natural gas properties, the establishment of maximum allowable rates of production from oil and natural gas wells, the regulation of well spacing, and plugging and abandonment of wells. The effect of these regulations is to limit the amount of oil and natural gas that we can produce from our wells and to limit the number of wells or the locations at which we can drill, although we can apply for exceptions to such regulations or to have reductions in well spacing. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil, natural gas and natural gas liquids within its jurisdiction.

The failure to comply with these rules and regulations can result in substantial penalties. Our competitors in the oil and natural gas industry are subject to the same regulatory requirements and restrictions that affect our operations.

Environmental, Health and Safety Regulation

General. Our operations are subject to stringent and complex federal, state, local and provincial laws and regulations governing environmental protection, health and safety, including the discharge of materials into the environment. These laws and regulations may, among other things:

require the acquisition of various permits before drilling commences;

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- restrict the types, quantities and concentration of various substances that can be released into the environment in connection with oil and natural gas drilling, production and transportation activities;

- limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas; and

- require remedial measures to mitigate pollution from former and ongoing operations, such as requirements to close pits and plug abandoned wells.

These laws and regulations may also restrict the rate of oil and natural gas production below the rate that would otherwise be possible. The regulatory burden on the oil and gas industry increases the cost of doing business in the industry and consequently affects profitability. Additionally, Congress and federal and state agencies frequently revise environmental, health and safety laws and regulations, and any changes that result in more stringent and costly waste handling, disposal and cleanup requirements for the oil and gas industry could have a significant impact on our operating costs.

The following is a summary of some of the existing environmental, health and safety laws and regulations to which our business operations are subject.

Waste Handling. The Resource Conservation and Recovery Act, or RCRA, and comparable state statutes, regulate the generation, transportation, treatment, storage, disposal and cleanup of hazardous and non-hazardous wastes. Under the auspices of the federal Environmental Protection Agency, or EPA, the individual states administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. Drilling fluids, produced waters and most of the other wastes associated with the exploration, development and production of crude oil or natural gas are currently regulated under RCRA s non-hazardous waste provisions. However, it is possible that certain oil and natural gas exploration and production wastes now classified as non-hazardous could be classified as hazardous wastes in the future. Any such change could result in an increase in our costs to manage and dispose of wastes, which could have a material adverse effect on our results of operations and financial position.

Comprehensive Environmental Response, Compensation and Liability Act. The Comprehensive Environmental Response, Compensation and Liability Act, or CERCLA, also known as the Superfund law, imposes joint and several liability, without regard to fault or legality of conduct, in connection with the release of a hazardous substance into the environment. Persons potentially liable under CERCLA include the current or former owner or operator of the site where the release occurred and anyone who disposed or arranged for the disposal of a hazardous substance to the site where the release occurred. Under CERCLA, such persons may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, damages to natural resources and the costs of certain health studies. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment.

We currently own, lease or operate and have formerly owned, leased or operated numerous properties that have been used for oil and natural gas exploitation and production for many years. Although we believe that we have utilized operating and waste disposal practices that were standard in the industry at the time, hazardous substances may have been released on, at or under the properties owned, leased or operated by us, or on, at or under other locations, including off-site locations, where such substances have been taken for disposal. In addition, some of our properties have been operated by third parties or by previous owners or operators whose handling, treatment and disposal of hazardous substances were not under our control. These properties and the substances disposed or released on, at or under them may be subject to CERCLA, RCRA and analogous state laws. Pursuant to such laws, we have in the past performed remediation of spills and releases resulting from our operations. In certain circumstances, we could be required to remove previously disposed substances and wastes,

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remediate contaminated property or perform remedial plugging or pit closure operations to prevent future contamination. In addition, federal and state trustees can also seek substantial compensation for damages to natural resources resulting from spills or releases.

Water Discharges. The Federal Water Pollution Control Act, or the Clean Water Act, and analogous state laws, impose restrictions and strict controls with respect to the discharge of pollutants, including oil and other substances generated by our operations, into waters of the United States or state waters. Under these laws, the discharge of pollutants into regulated waters is prohibited except in accordance with the terms of a permit issued by the EPA or an analogous state agency. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with discharge permits or other requirements of the Clean Water Act and analogous state laws and regulations.

The Safe Drinking Water Act, or SDWA, and analogous state laws impose requirements relating to our underground injection activities. Under these laws, the EPA and state environmental agencies have adopted regulations relating to permitting, testing, monitoring, record-keeping and reporting of injection well activities, as well as prohibitions against the migration of injected fluids into underground sources of drinking water. We currently own and operate a number of injection wells, used primarily for re-injection of produced waters, that are subject to SDWA requirements.

Air Emissions. The Federal Clean Air Act and comparable state laws regulate emissions of various air pollutants through air emissions permitting programs and the imposition of other requirements. In addition, EPA and certain states in which we operate have developed and continue to develop stringent regulations governing emissions of toxic air pollutants at specified sources. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with air permits or other requirements of the Federal Clean Air Act and analogous state laws and regulations.

The Kyoto Protocol to the United Nations Framework Convention on Climate Change became effective in February 2005. Under the Protocol, participating nations are required to implement programs to reduce emissions of certain gases, generally referred to as greenhouse gases, that are suspected of contributing to global warming. The United States is not currently a participant in the Protocol, and Congress has not acted upon recent proposed legislation directed at reducing greenhouse gas emissions. However, there has been support in various regions of the country for legislation that requires reductions in greenhouse gas emissions, and some states have already adopted legislation addressing greenhouse gas emissions from various sources, primarily power plants. The oil and natural gas industry is a direct source of certain greenhouse gas emissions, namely carbon dioxide and methane, and future restrictions on such emissions could impact our future operations. At this time, it is not possible to accurately estimate how potential future laws or regulations addressing greenhouse gas emissions would impact our business.

National Environmental Policy Act. Oil and natural gas exploration and production activities on federal lands are subject to the National Environmental Policy Act, or NEPA. NEPA requires federal agencies, including the Department of Interior, to evaluate major agency actions that have the potential to significantly impact the environment. In the course of such evaluations, an agency will prepare an Environmental Assessment that assesses the potential direct, indirect and cumulative impacts of a proposed project and, if necessary, will prepare a more detailed Environmental Impact Statement that may be made available for public review and comment. All of our current exploration and production activities, as well as proposed exploration and development plans, on federal lands require governmental permits that are subject to the requirements of NEPA. This process has the potential to delay the development of oil and natural gas projects.

Health, Safety and Disclosure Regulation. We are subject to the requirements of the federal Occupational Safety and Health Act, or OSHA, and comparable state statutes. The OSHA hazard communication standard, the

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Emergency Planning and Community Right to Know Act and similar state statutes require that we organize and/or disclose information about hazardous materials stored, used or produced in our operations.

We have incurred in the past, and expect to incur in the future, capital and other expenditures related to environmental compliance. Such expenditures, however, are included within our overall capital and operating budgets and are not separately accounted for. Although we believe that our continued compliance with existing requirements will not have a material adverse impact on our financial condition and results of operations, we cannot assure you that the passage of more stringent laws or regulations in the future will not have an negative impact on our financial position or results of operations.

Employees

As of December 31, 2006, we employed 299 people, including 166 employees in drilling and production, 45 in financial and accounting, 29 in land, 15 in exploration, 10 in reservoir engineering, 23 in administrative and 11 in information technology. Our future success will depend partially on our ability to attract, retain and motivate qualified personnel. We are not a party to any collective bargaining agreements and have not experienced any strikes or work stoppages. We consider our relations with our employees to be satisfactory. From time to time we utilize the services of independent contractors to perform various field and other services.

Legal Proceedings

We are not a party to any material pending legal proceedings, other than ordinary course litigation incidental to our business. While the ultimate outcome and impact of any proceeding cannot be predicted with certainty, our management believes that the resolution of any proceeding will not have a material adverse effect on our financial condition or results of operations.

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Management

Executive Officers and Directors

The following table sets forth names, ages and titles of our executive officers and directors:

Name	Age	Title
Harold G. Hamm(1)(3)	61	Chairman, Chief Executive Officer and Director
Mark E. Monroe(5)	52	President, Chief Operating Officer and Director
John D. Hart	39	Vice President, Chief Financial Officer and Treasurer
Jeffrey B. Hume	55	Senior Vice President Operations
Tom E. Luttrell	49	Senior Vice President Land
Jack H. Stark(4)	52	Senior Vice President Exploration and Director
Gene R. Carlson	53	Vice President Resource Development
Richard H. Straeter	48	President Illinois Division
Robert J. Grant(2)(5)	68	Director
George S. Littell(3)	62	Director
Lon McCain(1)(2)(5)	59	Director
H. R. Sanders, Jr.(1)(2)(4)	74	Director

(1) Member of the compensation committee.

(2) Member of the audit committee.

(3) Term expires in 2007.

(4) Term expires in 2008.

(5) Term expires in 2009.

Harold G. Hamm has served as Chief Executive Officer and a director since our inception in 1967 and currently serves as Chairman of the board of directors. He serves as Chairman of the board of directors of the general partner of Hiland Partners LP, one of our affiliates and a NASDAQ publicly traded midstream master limited partnership, and he serves as Chairman of the board of directors of the general partner of Hiland Holdings GP, LP (Hiland Holdings), also publicly traded on NASDAQ. Hiland Holdings owns the general partner interest and units in Hiland Partners LP. He also serves as a director of Complete Production Services, Inc., an NYSE publicly traded oil and gas service company. Mr. Hamm serves as Chairman of the Oklahoma Independent Petroleum Association. He was President of the National Stripper Well Association and founder and Chairman of Save Domestic Oil, Inc. and served on the Board of the Oklahoma Energy Explorers.

Mark E. Monroe became President and Chief Operating Officer in October 2005 and has served as a member of our board of directors since November 2001. He was Chief Executive Officer and President of Louis Dreyfus Natural Gas Corp. prior to its merger with Dominion Resources, Inc. in October 2001. After the merger, Mr. Monroe was a consultant and served as a member of the board of directors of Unit Corporation, an NYSE publicly traded onshore drilling and oil and gas exploration and production company from October 2003 through October 2005. Prior to the formation of Louis Dreyfus Natural Gas Corp. in 1990, he was Chief Financial Officer of Bogert Oil Company. He has served as Chairman of the Oklahoma Independent Petroleum Association, served on the Domestic Petroleum Council and the National Petroleum Council and on the boards of the Independent Petroleum Association of America, the Oklahoma Energy Explorers and the Petroleum Club of Oklahoma City. Mr. Monroe is a Certified Public Accountant and received his Bachelor of Business Administration degree from the University of Texas at Austin.

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John D. Hart became Vice President, Chief Financial Officer and Treasurer in November 2005. Prior to joining us, he was a Senior Audit Manager with Ernst & Young LLP. Mr. Hart was employed by Ernst & Young LLP from April 1998 to November 2005 and by Arthur Andersen LLP from December 1991 to April 1998. He is a member of the American Institute of Certified Public Accountants, Oklahoma Society of Certified Public Accountants and the Oklahoma Independent Petroleum Association. Mr. Hart graduated from Oklahoma State University with a Masters of Science in Accounting in December 1991.

Jeffrey B. Hume became our Senior Vice President of Operations in November 2006. He was previously elected as Senior Vice President of Resource and Business Development in October 2005, Senior Vice President of Resource Development in July 2002 and served as Vice President of Drilling Operations from 1996 to 2002. Prior to joining us in May 1983 as Vice President of Engineering and Operations, Mr. Hume held various engineering positions with Sun Oil Company, Monsanto Company and FCD Oil Corporation. Mr. Hume is a Registered Professional Engineer and member of the Society of Petroleum Engineers, Oklahoma Independent Petroleum Association and the Oklahoma and National Professional Engineering Societies. Mr. Hume graduated from Oklahoma State University with a Bachelor of Science degree in Petroleum Engineering Technology in 1975.

Tom E. Luttrell joined us as Senior Landman in April 1991 and was promoted to Senior Vice President Land in February 1997. Prior to joining us, Mr. Luttrell was a Senior Landman for Alexander Energy Corp. and Pacific Enterprises Oil Corp. Mr. Luttrell is currently a member of the Oklahoma Independent Petroleum Association legislative affairs committee. He is also a member of the Oklahoma Energy Explorers, American Association of Petroleum Landmen and several regional landman associations. Mr. Luttrell graduated from East Central Oklahoma State University in 1980 with a Bachelor of Business Administration. Mr. Luttrell is a past Chairman of the Northern Alliance of Independent Producers.

Jack H. Stark became Senior Vice President Exploration and a director in May 1998. Prior to joining us as Vice President of Exploration in June 1992, he was the exploration manager for the Western Mid-Continent Region for Pacific Enterprises. From 1978 to 1988, he held various staff and middle management positions with Cities Service Co. and TXO Production Corp. He is a member of the American Association of Petroleum Geologists, Oklahoma Independent Petroleum Association, Rocky Mountain Association of Geologists, Houston Geological Society and Oklahoma Geological Society. Mr. Stark holds a Masters degree in Geology from Colorado State University.

Gene R. Carlson became Vice President Resource Development in October 2005. He was an oil and gas consultant from March 2003 to October, 2005 and a founder and Chief Operating Officer for Encore Acquisition Company from its inception in April 1998 to March 2003. Mr. Carlson graduated from Texas A&M University with a Bachelor of Science degree in Mechanical Engineering.

Richard H. Straeter became President Illinois Division in October 2006. He was previously elected as President of Continental Resources of Illinois, Inc. (CRII) in April 2002. Prior to joining CRII, Mr. Straeter was employed by Barger Engineering, Inc. for 18 years as an engineering consultant and Vice President. He is a Registered Professional Engineer in Indiana, Illinois, Kentucky and Tennessee. Mr. Straeter is a past Chairman of the Illinois Basin Society of Petroleum Engineers and serves as a member of the National Petroleum Council, the Illinois Oil & Gas Association Board and the Ohio, Indiana, Kentucky and Michigan Oil and Gas Associations. Mr. Straeter earned his Bachelor of Science degree in Petroleum Engineering in 1983 and a Professional Engineering Degree (Honorary Masters) in 2004 from the University of Missouri-Rolla.

Robert J. Grant has been a director since January 2006. He was an audit partner of Deloitte & Touche LLP and a predecessor firm from 1969 to 2000. He served as partner in charge of the Dallas, Texas office audit department for ten years and a member of the firm s audit management group for twelve years. He has been a member of the Independent Petroleum Association of America, the American Petroleum Institute and the Texas Independent Producers and Royalty Owners Association and currently is a member of the American Institute of

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Certified Public Accountants and the Texas Society of Certified Public Accountants. Mr. Grant graduated from the University of Detroit with a MBA and BA in accounting.

George S. Littell has been a director since November 2004. He is a partner in the firm of Groppe, Long & Littell, a petroleum consulting firm. Prior to joining the firm in 1975, he held various positions in the natural gas, refining, supply and distribution and gas liquids departments of Mobil Oil Corporation. Mr. Littell received a Bronze Star for his service as an officer in the US Army, Vietnam in 1968-1969. He is a member of the International Association for Energy Economics, an Eagle Scout and a director of the Sam Houston Area Council for the Boy Scouts of America. Mr. Littell graduated from Yale University in 1966 and earned an MBA degree from New York University and a law degree from La Salle Extension University.

Lon McCain has been a director since February 2006. He was appointed a director of Cheniere Energy Partners, GP, LLC, the general partner of Cheniere Energy Partners, L.P., a publicly traded partnership, since April 2007. He was Vice President, Treasurer and Chief Financial Officer of Westport Resources Corporation, a publicly traded exploration and production company, from 2001 until the sale of Westport to Kerr McGee Corporation and his retirement in 2004. From 1992 until joining Westport in 2001, Mr. McCain was Senior Vice President and Principal of Petrie Parkman & Co., an investment banking firm specializing in the oil and gas industry. From 1978 until joining Petrie Parkman, Mr. McCain held senior financial management positions with Presidio Oil Company, Petro-Lewis Corporation and Ceres Capital. He was an Adjunct Professor of Finance at the University of Denver from 1982 through 2005. Mr. McCain currently serves on the board of Crimson Exploration, Inc., a domestic exploration and production company traded on the OTC Bulletin Board, and TransZap, Inc., a privately held provider of accounting software. Mr. McCain received a Bachelor of Business Administration and a Masters of Business Administration/Finance from the University of Denver.

H. R. Sanders, Jr. has been a director since November 2001. He served as a board member of Devon Energy Corporation from 1981 through 2000. In addition, he held the position of Executive Vice President for Devon Energy from 1981 until his retirement in 1997. From 1970 to 1981, Mr. Sanders was a Senior Vice President for Republic Bank of Dallas, N.A. with direct responsibility for independent oil, gas and mining loans. Mr. Sanders is a former member of the Independent Petroleum Association of America, Texas Independent Producers and Royalty Owners Association and Oklahoma Independent Petroleum Association, and a former director of Triton Energy Corporation. He currently serves on the board of Toreador Resources Corporation, a NASDAQ publicly traded oil and gas company with principal operations in France, Romania and Turkey.

Governance Matters

Our board of directors currently consists of seven members. Our directors are divided into three classes serving staggered three-year terms. Class I, Class II and Class III directors will serve until our annual meetings of shareholders in 2007, 2008 and 2009, respectively. At each annual meeting of shareholders, directors will be elected to succeed the class of directors whose terms have expired. This classification of our board of directors could have the effect of increasing the length of time necessary to change the composition of a majority of the board of directors. In general, at least two annual meetings of shareholders will be necessary for shareholders to effect a change in a majority of the members of the board of directors.

After the closing of this offering, we will be a controlled company within the meaning of the listing standards of the NYSE. Consequently, we will not be required to comply with certain of the NYSE s listed company requirements, such as the requirement to have a majority of independent directors on our board or the requirement to have compensation and governance committees comprised entirely of independent directors. However, we will still be required to have an independent audit committee under the NYSE s listed company requirements and will still be subject to SEC rules and regulations governing audit committees. As such, we will be required to have an audit committee consisting of independent directors as defined under the listing standards of the NYSE and under SEC rules and regulations. In addition, at least one member of the audit

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committee of our board of directors must meet the definition of an audit committee financial expert as defined under the SEC rules and regulations.

Board Committees

Our board of directors currently has an audit committee and a compensation committee. Our board may establish other committees from time to time to facilitate our management. Our full board will be responsible for overseeing director nomination and other governance functions.

Audit Committee. The principal functions of the audit committee are to assist the board in monitoring the integrity of our consolidated financial statements, the independent auditor s qualifications and independence, the performance of our independent auditors and our compliance with legal and regulatory requirements. The audit committee will have the sole authority to retain and terminate our independent auditors and to approve the compensation paid to our independent auditors. The audit committee also will be responsible for overseeing our internal audit function. The audit committee currently consists of Messrs. Grant, McCain and Sanders, with Mr. Grant acting as the Chairman. Messrs. Grant, McCain and Sanders are independent under the listing standards of the NYSE and under SEC rules and regulations.

Compensation Committee. The principal functions of the compensation committee are to determine awards to employees of stock or other equity compensation, establish performance criteria for and evaluate the performance of the chief executive officer and approve compensation of all senior executives and directors. The compensation committee is currently comprised of Messrs. Hamm, McCain and Sanders, with Mr. Sanders acting as the Chairman.

Compensation Committee Interlocks and Insider Participation

None of our executive officers has served as a member of a compensation committee (or if no committee performs that function, the board of directors) of any other entity that has an executive officer serving as a member of our board of directors.

Director Compensation

Directors who are not our employees are paid an annual retainer of $25,000 and $1,500 for each regular board of directors meeting attended. The Chairman of the audit committee is paid an additional annual retainer of $10,000, each Chairman of the other committees is paid an annual retainer of $2,500 and committee members other than the Chairman are paid an additional retainer of $1,000. A fee of $750 is paid for each special board meeting and $500 for each committee meeting attended.

Non-employee directors are also annually granted restricted stock with an approximate market value of $40,000 to vest over one year. In January 2006, 3,300 shares of restricted stock were granted each to Messrs. Grant, Littell and Sanders. In February 2006, 3,300 shares of restricted stock were granted to Mr. McCain. In January 2007, 3,300 shares of restricted stock were granted each to Messrs Grant, Littell, Sanders, and McCain.

2006 Director Compensation Table

The following table sets forth the compensation of our outside directors for the year ended December 31, 2006.

Name	**Fees Earned or Paid in Cash($)**	**Stock Awards($)(1)**	**Total($)**
Robert J. Grant	$44,083	$ 29,184	$ 73,267
George S. Littell	31,000	29,184	60,184
Lon McCain	32,499	26,752	59,251
H. R. Sanders Jr.	40,772	29,184	69,956

(1) Stock awards represent the value of restricted stock recognized during 2006. While we are a private company, we are required to purchase vested restricted stock at each director s request at a per share amount derived from our shareholders equity value adjusted quarterly for our PV-10.

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Management members of the board of directors are not compensated separately for their board service.

Compensation Discussion and Analysis

Overview. Prior to the completion of this offering, we have operated as a private company controlled by Harold G. Hamm, our founder, principal shareholder, Chairman of the Board and Chief Executive Officer. From our inception until the formation of the compensation committee in February 2006, Mr. Hamm had been solely responsible for reviewing and approving all compensation decisions relating to our executive officers, including those executive officers named in the Summary Compensation Table under Summary Compensation Table below. Mr. Hamm currently serves as a member of our compensation committee, which is responsible for implementing and administering all aspects of our benefit and compensation plans and programs, as well as developing specific policies regarding compensation of our executive officers.

Compensation Objectives. We are engaged in oil and natural gas exploration and exploitation activities in the Rocky Mountain, Mid-Continent and Gulf Coast regions of the United States. Our primary business goal is to increase shareholder value by finding and developing crude oil and natural gas reserves at costs that provide an attractive rate of return on our investment. We operate in a highly competitive environment for acquiring properties, marketing oil and natural gas and securing trained personnel. We believe that the loss of the services of our senior management or technical personnel could have a material adverse effect on our operations. Accordingly, we have designed our executive compensation program to attract, retain and motivate experienced, talented individuals to achieve our business goal, using the business strategies discussed in greater detail in this prospectus. Please read Business and Properties Our Business Strategy.

Implementing Our Objectives.

Determining Compensation. We rely upon our judgment in making compensation decisions, after reviewing the performance of the company and carefully evaluating an executive s contribution to that performance, including his business responsibilities, current compensation arrangements and long-term potential to enhance shareholder value. Specific operational and financial factors affecting compensation decisions for our named executive officers include reserve additions, finding and development costs, production volume and costs, earnings, cash flow, operating income and return on equity. We have not assigned specific individual goals to our executive officers that are used by the compensation committee in the determination of compensation for such officers.

We do not adhere to rigid formulas in determining the amount and mix of compensation elements. As described below, we rely on the formulaic achievement of financial goals only when establishing the aggregate bonus pool from which bonuses may be paid to all employees. We consider competitive market compensation paid by other companies similar in size and operations to us but we do not attempt to maintain a certain target percentile within that peer group or otherwise exclusively rely on those data to determine executive compensation. We incorporate flexibility into our compensation programs and in the assessment process to respond to and adjust for the evolving business environment.

Peer Compensation Group. The companies included in our compensation peer group (the Peer Group) are Bill Barrett Corporation, Denbury Resources Inc., Encore Acquisition Company, Quicksilver Resources Inc., Range Resources Corp., Southwestern Energy Company and St. Mary Land and Exploration Company. We selected these companies because they are publicly traded exploration and production companies similar in size and operations to us.

Elements of Compensation. The principal elements of the compensation program are a base salary, an annual cash bonus and a long-term incentive award. All cash bonus and equity awards for executive officers have been determined on a discretionary basis and have not been linked to the achievement of specific corporate goals or objectives.

Base Salary. The objective of the base salary component is to pay a competitive wage commensurate with such officer s experience, skills and responsibilities. From January 1, 1999 until September 15, 2004,

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Mr. Hamm elected not to receive a salary or annual bonus. In September 2004, he began to draw an annual salary of $350,000. On January 1, 2006, Mr. Hamm s annual salary was increased to $700,000 after a review of salary amounts paid to the chief executive officers of our Peer Group. The average cash compensation (salary and bonus) paid in 2005 to the highest paid named executive officer as reported in the proxy statements of the Peer Group was approximately $1.3 million compared to $986,539 paid to our CEO in 2006. The base salary of Mark E. Monroe, our President and Chief Operating Officer, was established through negotiations with him in connection with his initial employment in October 2005. Mr. Monroe s base has not been adjusted since such time.

With respect to our other executive officers, Mr. Hamm recommends to the compensation committee for approval the base salaries of the other executive officers generally after completion of an annual performance review conducted after each officer s anniversary hire date. In establishing the base salaries for the other executive officers during 2006, Mr. Hamm and our compensation committee considered the compensation paid to named executive officers by the Peer Group. The aggregate base salaries for our named executive officers, excluding Messrs. Hamm and Monroe, were increased 7.81% during 2006 in order to satisfy our objective of paying salaries at competitive levels. In the future, we expect that the base salaries of the executive officers will be reviewed on an annual basis and adjusted as necessary to remain competitive. We expect that future base salary adjustments for executive officers will be comparable to future adjustments made to executive officer base salaries by the Peer Group.

Annual Cash Bonus. Our executives may earn annual cash bonuses as a reward for our subjective evaluation of their individual contribution to the achievement of annual financial and operating results. The individual cash bonuses paid to executive officers for 2006 and prior years have been determined on a discretionary basis.

Annual cash bonuses are paid from a bonus pool that is equal to 0.375% of net income. Net income is reduced by 35 percent as an adjustment for income taxes not charged against book income because of our S-corporation status. If the conditions described below are met, the annual aggregate bonus pool for executive officers will be equal to 0.375% of earnings before interest expense, depreciation, depletion, amortization and accretion, property impairments, exploration expense and non-cash compensation expense (EBIDA), which results in a larger cash pool from which bonuses may be paid. We consider EBIDA to be a strong indicator of operating performance. The conditions that must be satisfied for the bonus pool to be established based on EBIDA rather than adjusted net income are:

- an increase in equivalent production for the current year compared to the prior year, and

- proved reserve additions from drilling activities of at least 120 percent of production.

During 2006, the first condition was satisfied as production increased 25% over 2005 levels. However, the second condition was not fully achieved as reserve additions from drilling activities were only 111 percent of production. In January 2007, we elected, with the approval of the compensation committee, to fund the bonus pool at 119% of the EBIDA level. In approving the larger bonus pool, our compensation committee considered several operational and financial criteria, including reserve additions, finding and development costs, production volume and costs, earnings, cash flow, operating income and return on equity. The criteria considered are not weighted, but are viewed collectively. The decision to waive the proved reserve condition was consistent with our compensation philosophy of examining several operational and financial criteria in determining annual cash bonuses.

We expect the compensation committee will modify the formal terms of our current bonus plan to be consistent with our compensation philosophy as described below. Therefore, we expect that our annual cash bonus pool will be funded on the basis of EBIDA if warranted by our overall operational, financial and stock performance even though one or both of the current bonus plan conditions are not satisfied.

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The bonus amount for each executive officer is determined at the discretion of the compensation committee. In addition, the compensation committee may elect to award annual cash bonuses to executive officers in an aggregate amount that exceeds the amount calculated from net income or EBIDA. Annual cash bonuses for executive officers are determined after completion of the year-end audited financial statements and reserve report. We have not adopted a policy regarding the adjustment or recovery of previously paid annual cash bonuses in the event our net income or EBIDA, as applicable, are restated or otherwise adjusted in a manner that would have the effect of reducing the size of the aggregate annual cash bonus pool.

In addition to the discretionary annual cash bonus awards made to our executive officers in 2006, an amount of $1,466,844 was accrued for the long-term incentive bonus to be paid to Mr. Monroe in October 2008 pursuant to his employment agreement, which is described in detail below in Employment Agreement. The total amount of the long-term incentive bonus will be paid to Mr. Monroe if he remains employed by us through October 2008. The formula for calculating the long-term incentive bonus was determined through employment agreement negotiations with Mr. Monroe and is reflected in the Non-Equity Incentive Plan Compensation column of the Summary Compensation Table below in Summary Compensation Table.

Long-term Incentive Awards. We did not grant any long-term incentive awards to our executive officers during 2006. We expect that restricted stock awards will be granted in 2007 to executive officers upon completion of our initial public offering approximating the number of prior awards vesting in 2006. Long-term incentive awards have been established to further our goals of retaining and motivating our executive officers. The awards granted to executive officers have been in the form of stock options and restricted stock designed to motivate the executive officers to increase the value of our common stock. The vesting provisions of the awards encourage our officers to remain in our employ in order to realize these forms of compensation. A description of our 2005 Long-Term Incentive Plan and the type of awards that may be granted is discussed below under Employee Benefit Plans. Each of our named executive officers was granted restricted stock vesting over a three-year period during 2005. The number of restricted shares, vesting period and other terms of the 2005 grants to individual executive officers was determined based upon the judgment of Mr. Hamm taking into account the factors described above under Implementing Our Objectives Determining Compensation. The value of unvested equity awards held by an individual was considered in the determination of the 2005 restricted stock awards and we expect that the value of unvested equity awards will be a factor in future awards.

Although our 2005 Long-Term Incentive Plan allows for various equity instruments, we currently intend to make future grants in the form of restricted stock. We intend to grant restricted stock because we believe restricted stock is a stronger motivational tool for employees. Restricted shares provide some value to an employee during periods of stock market volatility, while stock options may have a limited perceived value and may do little to retain and motivate employees when the current value of our stock is less than the option price. We have not established a policy with respect to the timing of long-term incentive awards to executive officers. We have also not adopted any common stock ownership requirements for our executive officers or policies regarding hedging the economic risk of such ownership.

The stock option awards provide for immediate vesting in the event of a change in control of the company, as defined by the 2000 Stock Option Plan, or the death of Mr. Hamm, so long as he holds 35% or more of our stock. The restricted stock awards provide for immediate vesting upon a change in control, as defined by the 2005 Long-Term Incentive Plan. Employees who remain in our employment after a change in control will immediately vest in their stock option and restricted stock awards. We would likely need the assistance of several key employees to successfully conclude a transaction that would result in a change of control. We believe that immediately vesting the awards may serve to reduce concerns, other than continued employment, that such employees may have with respect to any potential change in control transaction and

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may motivate them to complete the transaction. The termination or change-in-control provisions contained in the President s employment agreement are described below under Employment Agreement.

Our 2005 Long-Term Incentive Plan allows for the award of performance units and bonuses that vest upon the achievement of performance targets. The performance targets are based upon operational, financial and stock performance criteria, such as reserve additions, finding and development costs, production volume and costs, earnings, cash flow, operating income, return on equity, stock price appreciation and relative stock price performance. We have not awarded performance units or bonuses under the 2005 Long-Term Incentive Plan and have not determined if we will do so in the future.

Other. We provide automobiles to most executive officers and certain other employees for business and personal use. The personal use is valued according to IRS guidelines and reported as taxable income to the individuals. We value vehicle usage for disclosure in our public filings based on the aggregate incremental cost to us adjusted to reflect each individual s personal use of the vehicle.

We allow Mr. Hamm to use the corporate aircraft for personal trips. The value of such trips is calculated according to IRS guidelines and reported as taxable income to him. Aircraft usage is valued for disclosure in our public filings based on the aggregate incremental cost to us.

We have a defined contribution retirement plan (401(K)) covering all our full-time employees, including our executive officers. Our contributions to the plan are discretionary and based on a percentage of eligible compensation, excluding bonuses. Our contribution to the plan for each eligible employee during 2006 was 5% of such employee s covered compensation up to a maximum of $11,000. We currently plan to maintain the contribution level at 5% for 2007 and future years.

All full-time employees, including our executive officers, may participate in our health and welfare benefit programs, including medical, dental and vision care insurance and disability insurance. We provide all full time employees, including our executive officers, with life insurance coverage of the lesser of 1.5 times base salary or $50,000 and allow them to purchase incremental amounts above this. We do not sponsor any qualified or non-qualified defined benefit plans.

Indemnification Agreements

All of our directors and officers have entered into customary indemnification agreements with us, pursuant to which we have agreed to indemnify our directors and officers to the fullest extent permitted by law.

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Summary Compensation Table

The following table sets forth the compensation of our Principal Executive Officer, Principal Finance Officer, and the other three most highly compensated executive officers. We refer to these five individuals collectively as the named executive officers.

Name and Principal Position	Year	Salary($)	Bonus($)	Stock Awards($)(1)	Option Awards	Non-Equity Incentive Plan Compen-sation($)	Change in Pension Value and Nonqualified Deferred Compensation Earnings($)	All other Compensation($)(2)	Total($)
Harold G. Hamm Chairman, Chief Executive Officer and Director (Principal Executive Officer)	2006	$ 686,539	$ 200,000	$ 1,081,409				$ 95,597	$ 2,063,545
Mark E. Monroe President, Chief Operating Officer and Director	2006	450,000	175,000	953,377		1,466,844(3)		49,537	3,094,758
John D. Hart Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer)	2006	225,577	125,000	230,627				22,764	603,968
Jeffrey B. Hume Senior Vice President of Operations	2006	228,154	160,000	162,277				18,858	569,289
Jack H. Stark Senior Vice President and Director of Exploration	2006	223,500	155,000	162,277				27,094	567,871

(1) Stock Award amounts represent the value of restricted stock vesting during 2006. The associated grants were made during 2005 and vest 33.3 percent on each anniversary beginning in 2006. While we are a private company, we are required to purchase vested restricted stock at each employee s request at a per share amount derived from our shareholders equity value adjusted quarterly for our PV-10 as described in footnotes 1 and 9 to the Notes to Consolidated Financial Statements included elsewhere in this prospectus.

(2) All other compensation includes the following elements:

	Personal use of Company Airplane($)(a)	Personal use of Company Vehicle($)(b)	Company Contributions to 401(K) Plan($)	Cash Dividends Paid on Restricted Stock($)	Total($)
Harold G. Hamm	$ 36,527	$ 7,670	$ 11,000	$ 40,400	$ 95,597
Mark E. Monroe		2,934	11,000	35,603	49,537

John D. Hart	8,165	6,519	8,080	22,764
Jeffrey B. Hume	1,798	11,000	6,060	18,858
Jack H. Stark	10,034	11,000	6,060	27,094

(a) We calculate the incremental cost to the company of any personal use of the corporate aircraft based on the cost of fuel, trip-related maintenance, crew travel expenses, on-board catering, landing fees, trip-related hangar and parking costs, and smaller variable costs. Since the company-owned aircraft are used primarily for business travel, we do not include the fixed costs that do not change based on usage, such as pilots salaries and the purchase costs of the company-owned aircraft.

(b) We calculate the incremental cost to the company of any personal use of the company vehicles, including fuel, maintenance, insurance, lease payments and depreciation, as the vehicles are used primarily for personal use.

(3) Under the terms of his employment agreement, as described below under Employment Agreement, Mr. Monroe is entitled to receive a long-term incentive bonus on October 2, 2008. The bonus is determined by multiplying 193,895 by the excess of $30.91 over the fair market value of our common stock as of October 2, 2008. We value this obligation over the vesting period by the excess of $30.91 over the per share amount derived from our shareholders equity value adjusted quarterly for our PV-10 as described in footnotes 1 and 9 in the Notes to Consolidated Financial Statements included elsewhere in this prospectus. Upon becoming a public company, we will compare $30.91 to the publicly reported price at which our stock closes at each period end. Subject to certain conditions as described herein under Employment Agreement, Mr. Monroe is required to be employed on October 2, 2008, otherwise the bonus is forfeited.

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Outstanding Equity Awards at December 31, 2006

The following table sets forth information regarding stock option and restricted stock held by the named executive officers at December 31, 2006.

	Option Awards				Stock Awards	
	Number of Securities Underlying Unexercised Options(1)					
Name	**Exercisable(#)**	**Unexercisable(#)**	**Option Exercise Price($)**	**Option Expiration Date**	**Number of Shares or Units of Stock that Have Not Vested(#)(2)**	**Market Value of Shares of Stock That Have Not Vested($)(2)**
Harold G. Hamm(3)					146,674	$ 1,296,598
Mark E. Monroe(3)					129,250	1,142,570
John D. Hart(3)					29,337	259,304
Jeffrey B. Hume(3)	132,000		$ 0.64	October 1, 2010	22,000	194,480
	220,000		$ 1.27	October 1, 2010		
Jack H. Stark(3)	132,000		$ 0.64	October 1, 2010	22,000	194,480
	220,000		$ 1.27	October 1, 2010		
	88,000		$ 0.71	April 1, 2012		

(1) None of the named executive officers received grants or exercised stock options during 2006.

(2) Unvested shares will vest ratably on October 3, 2007 and 2008 for Mr. Monroe, October 5, 2007 and 2008, for Messrs Hamm, Hume and Stark, and November 30, 2007 and 2008 for Mr. Hart.

(3) None of the named executive officers are subject to an equity incentive plan.

Option Exercises and Restricted Stock Vested During 2006

The following table sets forth information regarding shares of restricted stock held by the named executive officers which vested during 2006. No options were exercised by the named executive officers during 2006.

Name	**Number of Shares Acquired on Vesting(#)**	**Value Realized on Vesting($)(1)**

Harold G. Hamm	73,333	$ 779,589
Mark E. Monroe	64,625	687,081
John D. Hart	14,663	155,894
Jeffrey B. Hume	11,000	116,950
Jack H. Stark	11,000	116,950

(1) Our named executive officers and other recipients of stock grants are only allowed to sell vested grants to us at a formula derived value per share, so long as we are a private company. Value realized on vesting is based on our shareholders equity adjusted for our PV-10 at September 30, 2006, which is the applicable valuation at the time of vesting.

Employee Benefit Plans

2005 Long-Term Incentive Plan

General. In October 2005 and as amended in April 2006, our board of directors and shareholders adopted and approved the Continental Resources, Inc. 2005 Long-Term Incentive Plan (the 2005 Plan). The purpose of the 2005 Plan is to provide our directors and our employees, advisors and consultants additional incentives that are designed to motivate them to put forth maximum effort toward the success and growth of the company and to enable the company and our affiliates to attract and retain experienced individuals. The 2005 Plan provides for the granting of incentive stock options intended to qualify under Section 422 of the Internal Revenue Code, options that do not constitute incentive stock options, restricted stock awards, stock appreciation rights, performance units and performance bonuses.

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Administration. Our board of directors has appointed the compensation committee thereof to administer the 2005 Plan. In general, the compensation committee is authorized to select the recipients of awards, establish the terms and conditions of those awards, accelerate the vesting, exercise or payment of an award or the performance period of an award, and determine to what extent a performance bonus may be deferred. In connection with the adoption of the 2005 Plan, our board of directors terminated our 2000 Stock Option Plan, described below.

Shares Subject to the 2005 Plan and Award Limits. The number of shares of our common stock that may be issued under the 2005 Plan may not exceed 5,500,000, subject to adjustment as described below. Shares of common stock that are attributable to awards that have expired, terminated or been canceled or forfeited, or have otherwise terminated without the issuance of an award, are available for issuance or use in connection with future awards. The maximum number of shares of common stock that may be subject to options and stock appreciation rights granted under the 2005 Plan to any one individual during any calendar year may not exceed 220,000 shares. The maximum number of shares of common stock that may be subject to restricted stock awards and performance unit awards granted under the 2005 Plan to any one individual during any calendar year may not exceed 220,000 shares. The maximum amount of compensation that may be paid under all performance bonuses under the 2005 Plan granted to any one individual during any calendar year may not exceed $1,000,000.

Options. The price at which a share of common stock may be purchased upon exercise of an option granted under the 2005 Plan, whether the option is an incentive stock option or an option that does not constitute an incentive stock option, will be determined by our board of directors or, with respect to awards granted to employees and consultants, the compensation committee, but the purchase price will not be less than the fair market value of a share of common stock on the date the option is granted. Options may be granted independently or in tandem with stock appreciation rights.

Stock Appreciation Rights. Our board of directors may grant stock appreciation rights independently of or in tandem with options to purchase common stock. A stock appreciation right allows the holder to receive, upon exercise of the right, an amount equal to the difference between the fair market value of the shares of our common stock on the exercise date and the exercise price stated in the award. The exercise price of a stock appreciation right can never be less than the fair market value of our common stock on the day of the award. The amount to be received upon exercise of a stock appreciation right will be paid in shares of our common stock.

Restricted Stock. Shares of common stock that are the subject of a restricted stock award under the 2005 Plan will be subject to restrictions on disposition by the holder of such award and an obligation of such holder to forfeit and surrender the shares to us under certain circumstances (the forfeiture restrictions). The forfeiture restrictions will be determined by our board of directors or the compensation committee, as applicable, and may provide that the forfeiture restrictions will lapse upon (a) continuous employment with, or in the case of an award granted to a director or consultant, service to, us or our affiliates, for a specified period of time, (b) the attainment of one or more operational, financial and/or stock performance criteria (the performance criteria) established by the board of directors or the compensation committee, as applicable, that are based on (1) reserve additions or replacements, (2) finding and development costs, (3) production volume, (4) production costs, (5) earnings (including net income or earnings before interest, taxes, depreciation and amortization (EBITDA)), (6) earnings per share, (7) cash flow, (8) operating income, (9) general and administrative expenses, (10) debt to equity ratio, (11) debt to cash flow ratio, (12) debt to EBITDA ratio, (13) EBITDA to interest ratio, (14) return on assets, (15) return on equity, (16) return on invested capital, (17) profit returns/margins, (18) stock price appreciation, (19) total shareholder return, and (20) relative stock price performance, or (c) a combination of any of the foregoing. In addition to acceleration of restricted stock awards upon a change of control of the company, our board of directors or compensation committee, as applicable, may provide that an award accelerates upon an eligible employee s retirement on or after his attainment of age 62, death or disability. Our board of directors may provide that a restricted stock award granted to a director or consultant will accelerate upon his resignation.

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Performance Units. A performance unit award under the 2005 Plan is an award of a monetary unit that may be earned based on performance during a performance period of one year or more. At the time of the grant of a performance unit award, our board of directors or the compensation committee, as applicable, will establish the target, maximum and minimum value of each performance unit, the applicable performance criteria, and time period over which the performance will be measured. Payment of a performance unit award may be in cash or shares of common stock, as determined in the sole discretion of our board of directors.

Performance Bonuses. A performance bonus under the 2005 Plan is an award that provides for a payment that may be earned based on a performance during a period of one year or more. At the time of the grant of a performance bonus under the 2005 plan, our board of directors or the compensation committee, as applicable, will establish the amount that may be earned as a performance bonus under the award and the applicable performance criteria. Payment of a performance bonus award may be in cash or shares of common stock, as determined in the sole discretion of our board of directors or compensation committee, as applicable.

Change of Control. All awards under the 2005 Plan become fully vested, fully earned and exercisable upon the occurrence of a change of control of the company, as defined in the 2005 Plan. The value of the affected awards for our named executive officers as of December 31, 2006 is set forth under Outstanding Equity Awards at December 31, 2006. Additionally, Mr. Monroe is subject to an employment agreement which provides for payment of 2 years of salary and bonus under certain circumstances as described under Employment Agreement.

Amendment and Termination of the 2005 Plan and Awards. The maximum term of any award under the 2005 Plan is 10 years. No awards under the 2005 Plan may be granted after 10 years from its effective date (October 3, 2005). The 2005 Plan will remain in effect until all awards granted under the 2005 Plan have been settled. Our board of directors, in its discretion, may terminate the 2005 Plan at any time with respect to any shares of our common stock for which awards have not been granted. Our board of directors may amend the 2005 Plan in any manner, but any amendment to increase the maximum aggregate number of shares that may be issued under the 2005 Plan (except by operation of the 2005 Plan s adjustment provision), materially modify the class of individuals eligible to receive awards under the 2005 Plan, or materially increase the benefits to participants under the 2005 Plan requires the approval of our shareholders. No change in any award previously granted under the 2005 Plan may be made which would impair the rights of the holder of such award without the consent of the holder. Our board of directors is prohibited from canceling, reissuing or modifying an award under the 2005 Plan if such action will have the effect of repricing the award.

Adjustments. The maximum numbers of shares of common stock that may be issued under the 2005 Plan, and the number of shares subject to any award that has been granted under the 2005 Plan, are subject to adjustment to reflect stock dividends, stock splits, recapitalizations and similar changes in our capital structure. Under the 2005 Plan, we will not make such adjustments unless they would cause at least a 1% increase or decrease in the number of shares subject to any award available under the 2005 Plan.

2000 Stock Option Plan

General. In October 2000, our board of directors and shareholders adopted and approved the Continental Resources, Inc. 2000 Stock Option Plan (the 2000 Plan). In connection with the adoption of the 2005 Plan, our board of directors terminated the 2000 Plan, except with respect to unexercised options outstanding under the 2000 Plan. The purpose of the 2000 Plan was to provide our directors and employees and employees of our affiliates additional incentives that are designed to motivate them to put forth maximum effort toward the success and growth of the company and to enable us and our affiliates to attract and retain experienced individuals. The 2000 Plan provided for the granting of incentive stock options intended to qualify under Section 422 of the Internal Revenue Code and options that do not constitute incentive stock options.

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Administration. In February 2006, our board of directors authorized the compensation committee to administer the 2000 Plan for the purposes of awards previously granted to our employees and employees of our affiliates and consultants. In general, our compensation committee is authorized to select the recipients of options, establish the options terms and conditions, and accelerate such options when to do so would be in the best interest of the company.

Options Granted Under the 2000 Plan. Up to 11,220,000 shares of common stock were originally made available for issuance under the 2000 plan, subject to adjustment as described below. Prior to the termination of the 2000 Plan, options to purchase a total of 2,387,000 shares of common stock were issued. Our board of directors determined the price at which a share of common stock may be purchased upon exercise of an option granted under the 2000 Plan at the time of the grant. In the case of an option that does not constitute an incentive stock option, the exercise price could not be less than 50% of the fair market value of the common stock on the date the option was granted. In the case of an incentive stock option, the exercise price could not be less than 100% of the fair market value of the common stock on the date the option was granted. At the time of the grant of any option or at any time thereafter up until the time of any dividend payment by us, our board of directors could choose to include as part of such award the right to receive dividends or dividend equivalents with respect to such award. The compensation committee has discretion to accelerate the vesting of an option upon the death, disability or termination of the grantee s service to the company under special circumstances (as determined by the compensation committee).

Merger, Dissolution, Change of Control, Death of Harold G. Hamm. If we merge, sell substantially all of our assets or dissolve or liquidate and provision is not made in such transaction for the surviving, resulting or acquiring corporation to assume or substitute our outstanding options, such options will automatically vest and become fully exercisable prior to such transaction. If we undergo a change of control (as defined under the 2000 Plan) or Mr. Hamm dies at a time when 35% or more of the total voting power of our voting stock is beneficially owned by Mr. Hamm (individually and as trustee of his revocable inter vivos trust established in April 1984), then all outstanding options will automatically fully vest.

Amendment and Termination of the 2000 Plan and Awards. The maximum term of any award under the 2000 Plan is 10 years. No change in any option previously granted under the 2000 Plan may be made that would be adverse to the holder of such option without the consent of the holder.

Adjustments. The number of shares subject to any award that has been granted under the 2000 Plan is subject to adjustment to reflect stock dividends, stock splits, recapitalizations and similar changes in our capital structure. Under the 2000 Plan, we will not make such adjustments unless they would cause at least a 1% increase or decrease in the number of shares subject to any option granted under the 2000 Plan.

Employment Agreement

We have entered into an employment agreement with Mark E. Monroe, our President and Chief Operating Officer. The agreement provides for a minimum annual salary of $450,000 during each of the years ended October 2, 2006, 2007 and 2008.

The agreement provides for a long-term incentive bonus payable if Mr. Monroe remains continuously employed by the company through the term of the agreement. The long-term incentive bonus is determined by multiplying 193,875 by the excess of $30.91 over the fair market value of our common stock as of October 2, 2008.

On October 3, 2005, we granted Mr. Monroe 193,875 shares of restricted stock, which vest ratably over a three-year period.

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Payments in the Event of Termination

The employment agreement with Mr. Monroe requires that we pay to him, in a single lump-sum payment (payable as soon as practicable following termination and in compliance with section 409A of the Code), an amount equal to sum of (a) two times his average annual compensation (defined below), and (b) his termination long term bonus amount (as defined below) in the event we terminate him without cause (as defined below) or he resigns for good reason (as defined below).

Mr. Monroe s average annual compensation is the average of his annualized compensation, base salary and bonus, paid under his employment agreement for the two year period of employment (or if employed less than two years, then the period of employment) immediately preceding his date of termination. As of December 31, 2006, Mr. Monroe s average annual compensation was $630,000. As result, under clause (a), Mr. Monroe would have been entitled to a lump-sum payment of $1.26 million as of December 31, 2006.

Mr. Monroe s termination long term bonus amount is the amount equal to the product of (a) 193,875, and (b) the excess of $30.91 over the value of the company s common stock. Until our stock becomes publicly traded, the value of our common stock is the internal valuation based on the book value of our shareholders equity adjusted for PV-10 as of each calendar quarter, which was $8.84 per share as of December 31, 2006. As a result, as of December 31, 2006, Mr. Monroe s termination long term bonus amount would have been $4.28 million.

In addition, we will maintain for the benefit of Mr. Monroe (and his spouse and/or his dependents, as applicable) for a period of 18 months the medical, hospitalization, and dental programs in which he (and his spouse and/or dependents, as applicable) participated immediately prior to his date of termination; provided, however, that if Mr. Monroe (his spouse and/or his dependents, as applicable) is eligible for Medicare or a similar type of governmental medical benefit, such benefit shall be the primary provider before our medical benefits are provided; and provided further, if Mr. Monroe (and his spouse and/or his dependents, as applicable) cannot continue to participate in our programs providing such benefits (e.g., the terms of the plans do not permit participation by former employees), then we will arrange to provide Mr. Monroe (and his spouse and/or his dependents, as applicable) with the economic equivalent of such benefits. Notwithstanding, if Mr. Monroe becomes reemployed with another employer and is eligible to receive medical, hospitalization and dental benefits under another employer-provided plan, the benefits described above will be secondary to those provided under such other plan during the applicable period. As of December 31, 2006, the value of this benefit would have been approximately $24,000.

In the event of the termination of Mr. Monroe s employment as a result of his death or disability he is entitled to his termination long term bonus amount as soon as practicable following such termination.

Mr. Monroe s employment agreement defines cause as: (a) his conviction by a federal or state court of competent jurisdiction of a felony which relates to his employment at the company; (b) an act or acts of dishonesty taken by him and intended to result in substantial personal enrichment to him at the expense of the company; or (c) his willful failure to follow a direct, reasonable and lawful written directive from his supervisor or the board of directors, within the reasonable scope of his duties, which failure is not cured to the satisfaction of the board of directors within thirty (30) days. For purposes of this definition of cause : (x) no act or omission by Mr. Monroe will be deemed willful unless done, or omitted by him in bad faith and without reasonable belief that his action or omission was in the best interest of the company; and (y) Mr. Monroe will not be deemed to have been terminated for cause unless and until the company delivers to him a copy of the resolution duly adopted by the affirmative vote of not less than three-fourths (3/4ths) of the entire membership of the board of directors, at a meeting of the board of directors called and held for such purpose (after reasonable notice to him and an opportunity for him, together with his counsel, to be heard before the board of directors), finding that in the good faith opinion of the board of directors, he was guilty of conduct set forth in clauses (a), (b), or (c) above and specifying the particulars thereof in detail.

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Mr. Monroe s employment agreement defines good reason as: (a) the company s assignment to him of any duties inconsistent in any respect with his position (including status, offices, titles and reporting requirements), authority, duties or responsibilities; (b) the reduction of the rate of his base salary below $450,000 other than as a part of a compensation reduction program which applies equally to all executives at the vice president and above levels; (c) the company requiring him to be based at any office or location outside of the greater Enid, Oklahoma, metropolitan area, except for travel reasonably required in the performance of his responsibilities; or (d) any failure by the company to provide indemnification to him in same manner as provided to other executive officers.

Mr. Monroe s employment agreement also contains standard confidentiality and non-solicitation provisions. In the event of Mr. Monroe s termination by us without cause or by him for good reason, the non-solicitation provision is effective so long as Mr. Monroe is receiving benefits or payments under the employment agreement.

Payments in the Event of Change in Control

In the event of a change in control of the company (as defined below), the unvested shares of restricted stock held by our executive officers will fully vest. This offering will not constitute a change in control of the company.

A change in control means:

(a) any transaction in which shares of voting securities of the company representing more than 50% of the total combined voting power of all outstanding voting securities of the company are issued by the company, or sold or transferred by the shareholders of the company as a result of which those persons and entities who beneficially owned voting securities of the company representing more than 50% of the total combined voting power of all outstanding voting securities of the company immediately prior to such transaction cease to beneficially own voting securities of the company representing more than 50% of the total combined voting power of all outstanding voting securities of the company immediately after such transaction;

(b) the merger or consolidation of the company with or into another entity as a result of which those persons and entities who beneficially owned voting securities of the company representing more than 50% of the total combined voting power of all outstanding voting securities of the company immediately prior to such merger or consolidation cease to beneficially own voting securities of the company representing more than 50% of the total combined voting power of all outstanding voting securities of the surviving corporation or resulting entity immediately after such merger of consolidation; or

(c) the sale of all or substantially all of the company s assets to an entity of which those persons and entities who beneficially owned voting securities of the company representing more than 50% of the total combined voting power of all outstanding voting securities of the company immediately prior to such asset sale do not beneficially own voting securities of the purchasing entity representing more than 50% of the total combined voting power of all outstanding voting securities of the purchasing entity immediately after such asset sale.

Listed in the following table is the value of unvested shares of restricted stock held by our named executive officers as of December 31, 2006, which would fully vest in the event of a change of control. The per share value is the formula price as of December 31, 2006, at which we are required to purchase vested restricted stock upon an holder s request. Also included in the table is the value of termination payments due to Mr. Monroe pursuant to his employment agreement as described under Payments in the Event of Termination.

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Payments in the event of change in control or termination:

	Early Vesting of Restricted Stock	Termination Payment	Total
Harold G. Hamm	$ 1,296,598		$ 1,296,598
Mark E. Monroe	1,142,570	$ 5,562,000	6,704,570
John D. Hart	259,304		259,304
Jeffrey B. Hume	194,480		194,480
Jack H. Stark	194,480		194,480

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Selling Shareholder and Security Ownership of Certain Beneficial Owners and Management

The following table sets forth certain information regarding the beneficial ownership of our common stock prior to and as of the closing of this offering by:

- the selling shareholder and each other person who will beneficially own more than 5% of our common stock then outstanding;
- each of our named executive officers;
- each of our directors; and
- all of our directors and executive officers as a group.

All information with respect to beneficial ownership has been furnished by the respective directors, officers or 5% or more shareholders, as the case may be. The information in the following table gives effect to our 11 for 1 stock split to be effected in the form of a stock dividend concurrent with the consummation of this offering and assumes that the underwriters do not exercise their overallotment option:

	Shares beneficially owned prior to offering				Shares offered hereby	Shares of common stock beneficially owned after offering	
	Voting common stock		Non-voting common stock(1)				
Name of Beneficial Owner	Number	% of class	Number	% of class	Number	Number	%
Harold G. Hamm(2)(3)(4)	7,170,526	90.7%	136,460,082(5)	90.2%	20,650,000	122,980,608	73.2%
Harold Hamm DST Trust(3)	439,406	5.6%	8,348,681	5.5%		8,788,087	5.2%
Harold Hamm HJ Trust(4)	292,974	3.7%	5,566,440	3.7%		5,859,414	3.5%
Mark E. Monroe			193,875(6)	*		193,875(6)	*
John D. Hart			39,204(7)	*		39,204(7)	*
Jeffrey B. Hume			385,000(8)	*		385,000(8)	*
Tom E. Luttrell			209,000(9)	*		209,000(9)	*
Jack H. Stark			469,403(10)	*		469,403(10)	*
Gene R. Carlson			36,663(11)	*		36,663(11)	*
Richard H. Straeter			73,326(9)	*		73,326(9)	*
Robert J. Grant			6,600(12)	*		6,600(12)	*

George S. Littell			6,600(12)	*		6,600(12)	*
Lon McCain			6,600(13)	*		6,600(13)	*
H. R. Sanders, Jr.			6,600(12)	*		6,600(12)	*
All directors and executive officers as a group (11 persons)	7,170,526	90.7%	137,892,953(14)	90.5%	20,650,000	124,413,479(14)	74.1%

* Less than 1%.

(1) All shares of non-voting common stock will become voting shares of common stock after the consummation of this offering.

(2) Mr. Hamm holds his shares through the Revocable Inter Vivos Trust of Harold G. Hamm, for which Mr. Hamm is both the trustee and sole beneficiary. The address of the Revocable Inter Vivos Trust of Harold G. Hamm is 302 N. Independence, Enid, Oklahoma 73701.

(3) The Harold Hamm DST Trust is a trust established for the benefit of children of Harold G. Hamm. Mr. Hamm is neither the trustee nor the beneficiary of the Harold Hamm DST Trust. Mr. Hamm disclaims beneficial ownership of the shares of our common stock owned by the Harold Hamm DST Trust, and none of these shares are shown as being beneficially owned by Mr. Hamm in the table above. Mr. Bert Mackie is the trustee of the Harold Hamm DST Trust, and his address is c/o Security National Bank, 201 West Broadway, Enid, Oklahoma 73702-1272.

(4) The Harold Hamm HJ Trust is a trust established for the benefit of children of Harold G. Hamm. Mr. Hamm is neither the trustee nor the beneficiary of the Harold Hamm HJ Trust. Mr. Hamm disclaims beneficial ownership of the shares of our common stock owned by the Harold Hamm HJ Trust, and none of these shares are shown as being beneficially owned by Mr. Hamm in the table above. Mr. Bert Mackie is the trustee of the Harold Hamm HJ Trust, and his address is c/o Security National Bank, 201 West Broadway, Enid, Oklahoma 73702-1272.

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(5) Includes 146,674 shares of restricted stock which vest 50% on each of October 5, 2007 and October 5, 2008.

(6) Includes 129,250 shares of restricted stock which vest 50% on each of October 3, 2007 and October 3, 2008.

(7) Includes 29,337 shares of restricted stock which vest 50% on each of November 30, 2007 and November 30, 2008.

(8) Includes 22,000 shares of restricted stock which vest 50% on each of October 5, 2007 and October 5, 2008, and options to purchase 352,000 shares of our common stock exercisable within 60 days of the date of this prospectus.

(9) Represents shares of non-voting common stock issuable upon the exercise of options to purchase our common stock exercisable within 60 days of the date of this prospectus.

(10) Includes 22,000 shares of restricted stock which vest 50% on each of October 5, 2007 and October 5, 2008, and options to purchase 440,000 shares of our common stock exercisable within 60 days of the date of this prospectus.

(11) Includes 24,442 shares of restricted stock which will vest 50% on each of November 1, 2007 and November 1, 2008.

(12) Represents 3,300 shares of restricted stock granted each in January 2006 and 2007, which vest after a period of one year.

(13) Represents 3,300 shares of restricted stock granted each in February 2006 and January 2007, which vest after a period of one year.

(14) Includes 578,545 shares of restricted stock and options to purchase up to 1,074,326 shares of our non-voting common stock exercisable within 60 days of the date of this prospectus.

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Certain Relationships and Related Party Transactions

In February 2006, our board of directors amended the audit committee charter to require that the audit committee review all related party transactions (as defined below) and recommend approval or disapproval to the board of any such transaction. A related party transaction is a transaction, proposed transaction, or series of similar transactions, in which (a) we are a participant, (b) the amount involved exceeds $120,000 and (c) a related person (as defined below) has or will have a direct or indirect material interest. A related person is (a) any person who is, or at any time since the beginning of our last fiscal year was, a director, executive officer, or nominee to become a director, (b) a person known to be the 5% beneficial owner of any class of our voting securities, (c) an immediate family member of any of the foregoing persons, which means any child, stepchild, parent, stepparent, spouse, sibling, mother-in-law, father-in-law, son-in-law, daughter-in-law, brother-in-law, or sister-in-law of such director, executive officer, nominee for director or more than 5% beneficial owner, and (d) any person (other than a tenant or employee) sharing the household of such director, executive officer, nominee for director or more than 5% beneficial owner. The audit committee considers the adequacy of disclosure and fairness to us of the matters considered. The audit committee adopted a written policy which includes factors for committee members to consider in exercising their judgment including (a) terms of the transaction with the related party, (b) availability of comparable products or services from unrelated third parties, (c) terms available from unrelated third parties and (d) the benefits to us. The audit committee will recommend for approval only those related party transactions that are, in their judgment, in our best interests and on terms no less favorable to us than we could have achieved with an unaffiliated party.

Crude Oil Sales

During the years ended December 31, 2005 and 2006, we sold approximately 1.3 MMBbls and 1.2 MMBbls of oil from properties located in North Dakota and Montana to Banner Pipeline Company, L.L.C. (Banner) for $67.6 million and $61.5 million, respectively. Our principal shareholder and his family trusts owned 100% of the common stock of Banner. Our sales to Banner were based on market prices and considered to be on terms equivalent to arms length transactions. In February 2006, we decided to market the majority of our crude oil in the Rocky Mountain region directly or through a wholly owned subsidiary rather than through an affiliate, and, as Banner has existing contacts and relationships with crude oil purchasers, we decided to purchase Banner. On March 30, 2006, we acquired Banner for approximately $8.8 million, the book value of working capital, principally cash, accounts receivable, crude oil inventory and accounts payable.

During the years ended December 31, 2004 and 2005, we sold approximately 351 MBbls of oil from properties located in Wyoming to Independent Trading & Transportation Company I, L.L.C. or a subsidiary thereof (ITT) for $10.8 million and 263 MBbls for $11.0 million, respectively. Our principal shareholder and his family own 100% of the common stock of ITT. Effective March 2006, we ceased selling oil to ITT. We sold 97 MBbls of oil for $3.7 million during 2006 prior to the cessation of sales to ITT.

We operated crude oil gathering lines in North Dakota and Wyoming on behalf of ITT for which they paid us approximately $236,000, $344,000 and $836,000 during the years ended December 31, 2004, 2005 and 2006, respectively. We paid ITT approximately $398,000, $692,000 and $854,000 for crude oil gathering services in North Dakota during the years ended December 31, 2004, 2005 and 2006, respectively. We believe that our transactions with ITT have been on terms equivalent to arm s-length transactions.

Natural Gas Sales

During the years ended December 31, 2004, 2005 and 2006, we sold approximately 2,394 MMcf for $8.2 million, 4,733 MMcf for $30.3 million and 5,240 MMcf for $29.1 million, respectively, to affiliated natural gas gathering and processing companies owned by our principal shareholder and previous executive officers.

Additionally, we paid approximately $2.6 million, $10.5 million and $8.4 million for reclaimed oil and residue fuel gas from such companies during the years ended December 31, 2004, 2005 and 2006, respectively. The affiliated natural gas gathering and processing companies were combined into Hiland Partners, LP (Hiland), a publicly traded midstream master limited partnership, in October 2004. Our principal shareholder and his family trusts own the majority of the total outstanding units of Hiland and control its general partner. Our principal shareholder also serves as the Chairman of the Board of Directors of Hiland s general partner. Our sales to and purchases from Hiland are based on market prices and considered to be on terms equivalent to arm s-length transactions. We are generally prohibited, under the terms of an agreement with Hiland, from engaging in the gathering, treating, processing and transportation of natural gas in North America and buying or selling any assets related to the forgoing businesses until February 15, 2010.

On November 8, 2005, we entered into a contract with Hiland for the processing and treatment of gas produced from the CHNU and CHWU. Under the terms of the contract, we agree to deliver low pressure gas to Hiland for compression, treatment and processing at a facility to be constructed by Hiland. Nitrogen and carbon dioxide must be removed from the gas production associated with the increasing oil production from CHNU and CHWU for the gas production to be marketable. Under the terms of the contract, we pay $0.60 per Mcf in gathering and treating fees, and 50% of the electrical costs attributable to compression and plant operation and receive 50% of the proceeds from residue gas and plant product sales. After we deliver 36 Bcf of gas, the $0.60 per Mcf gathering and treating fee is eliminated. If the average composite volume of carbon dioxide is less than 10%, we pay an additional $0.10 per Mcf treating fee, otherwise the treating fee is $0.20 per Mcf. Through December 31, 2006, we have invested $1.7 million and anticipate investing approximately $4.3 million during 2007 to construct gas gathering from each well to central tank battery delivery points. The plant is currently expected to be operational in April 2007. The terms of our contract with Hiland were determined following arm s-length negotiations between our representatives and representatives of Hiland. We believe the terms contained in this agreement are comparable to those we would receive from an unaffiliated third party.

Oilfield Services

During the years ended December 31, 2004, 2005 and 2006, we paid approximately $14.5 million, $20.4 million and $31.4 million, respectively, to affiliated service companies for oilfield services such as saltwater hauling and workover rigs. A portion of such amount was billed to other interest owners. Prior to October 2004, our principal shareholder owned a majority of the common stock of the affiliated service companies. After such date, the assets of the affiliated service companies were conveyed to Complete Production Services, Inc. (Complete). Our principal shareholder serves on the board of directors of Complete and trusts formed by him currently own approximately 7% of the stock of Complete. We believe that our transactions with the affiliated service companies have been on terms no less favorable to us than we could have achieved with an unaffiliated party.

Pursuant to a strategic customer relationship agreement with Complete, we agree to use commercially reasonable efforts to provide the service companies a first right to provide services or supplies required in our operations so long as such services or supplies can be provided on a timely basis and at competitive market prices. The service companies agree to use commercially reasonable efforts to provide us with requested supplies and services ahead of and before any such supplies and services would otherwise be provided to any other customer who is not then being provided supplies and services pursuant to a binding agreement. The strategic customer relationship agreement can be terminated by either party on or after October 2009.

During the years ended December 31, 2004, 2005 and 2006, we paid for costs of approximately $1.2 million, $3.1 million and $5.6 million, respectively, for daywork drilling rig services provided by United Drilling Co. (United). A portion of such amounts was billed to other interest owners. United provided daywork drilling rig services for four wells in 2004, eight wells in 2005 and 11 wells in 2006. Our principal shareholder owns

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100% of the common stock of United. We believe that our transactions with United have been on terms no less favorable to us than we could have achieved with an unaffiliated party.

We signed a Compression Services Agreement effective as of January 28, 2005 with Hiland covering the Cedar Hills North and South Medicine Pole Hills Units whereby Hiland agrees to provide to us on a monthly basis the quantities of compressed air and pressurized water that we request. We have agreed to provide, at no cost to Hiland, all fuel, whether gas or electric, and water, in the quantities necessary for Hiland to provide such services. The term of the contract is for four years from the effective date at a cost of approximately $402,000 per month. In 2004, we were responsible for operating and maintaining the compression equipment and paid Hiland and a predecessor affiliated gas gathering and processing company $3.8 million for rental of the compression equipment. The annual cost of renting the compression equipment was compared against proposals submitted by third parties and the compression equipment rental terms are considered to be no less favorable than we could have achieved with an unaffiliated party. The incremental annual cost of approximately $1 million being paid under the new contract represented our estimate of the annual wages and overhead associated with our eleven employees that operated the compression equipment and the annual cost of maintaining the compression equipment. Under the agreement, Hiland is respo